APPENDIX 4

CHARACTERIZATION OF OIL AND GAS PRODUCTION EQUIPMENT AND DEVELOP A METHODOLOGY TO ESTIMATE STATEWIDE EMISSIONS AND SPECIFIED OIL AND GAS WELL ACTIVITIES EMISSIONS INVENTORY UPDATE

ERG No. 0227.03.026
TCEQ Contract No. 582-7-84003
Work Order No. 582-7-84003-FY10-26

Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions

FINAL REPORT

TCEQ Contract No. 582-7-84003
Work Order No. 582-7-84003-FY10-26

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List of Acronyms

Acronym	Definition
BBL	Barrels
CENRAP	Central Regional Air Planning Association
CO	Carbon Monoxide
DFW	Dallas-Fort Worth
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERG	Eastern Research Group
HAP	Hazardous Air Pollutants
HARC	Houston Advanced Research Center
Hp-Hr	Horsepower Hour
Hp	Horsepower
hr/yr	Hours per year
lbs	Pounds
MMBtu/hr	Million British Thermal Units per hour
MMscf	Million standard cubic feet
Mscf	Thousand standard cubic feet
NEI	National Emissions Inventory
NIF	NEI Input Format
NO_x	Nitrogen Oxides
NSCR	Non selective catalytic reduction
NSPS	New Source Performance Standard
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
RVP	Reid Vapor Pressure
SCC	Source Classification Code
scf	Standard cubic feet
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
STP	Standard temperature and pressure
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TERC	Texas Environmental Research Consortium
TexAER	Texas Air Emissions Repository
TOC	Total Organic Carbon
TRC	Texas Railroad Commission
VOC	Volatile Organic Compound

EXECUTIVE SUMMARY

This report is a deliverable for Texas Commission on Environmental Quality (TCEQ) Work Order No. 582-07-84003-FY10-26 to better identify and characterize area source emissions from upstream onshore oil and gas production sites that operated in Texas in 2008, and to develop a 2008 base year air emissions inventory from these sites. On an individual basis, emissions from any single oil and gas production site are likely minimal as there may only be a few pieces of equipment at any one site. This equipment could include storage tanks, dehydrators, oil and gas piping, or small natural gas fired engines. However, with over 90,000 gas wells and 150,000 oil wells in Texas, the cumulative magnitude of these emissions may be significant. In particular, due to recent advancements in exploration and production technology such as the hydraulic fracturing of natural gas wells, this activity is increasingly taking place in populated areas, including ozone nonattainment areas. Therefore, closer scrutiny and evaluation of this area source category is warranted.

Emissions estimates developed from this inventory project may be used for improved input data to photochemical air quality dispersion modeling, emissions sensitivity analyses, State Implementation Plan (SIP) development, and other agency activities.

The emissions inventory developed under this project addresses area source criteria pollutant emissions of volatile organic compounds (VOC), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and sulfur dioxide (SO_2); certain Hazardous Air Pollutant (HAPs) emissions such as benzene, toluene, ethylbenzene, and xylene from dehydrators, oil and condensate storage tanks, and oil and condensate loading racks; and a variety of HAPs from combustion sources.

This study builds on three previous studies ERG conducted for TCEQ to estimate emissions from oil and gas exploration and production activities. The first, implemented in 2007, focused on compiling a state-wide emissions inventory (including both onshore and offshore sources) for oil and gas exploration and production for a 2005 base year (TCEQ, 2007). The second study, conducted in 2009 for a 2008 base year, focused only on emissions from onshore oil and gas well drilling rig engines (TCEQ, 2009). The third study, which was just completed, developed an emissions inventory for offshore oil and gas platforms (TCEQ, 2010). In contrast, this current study addresses onshore area sources (those not included in the Texas point source inventory). Collectively, these studies provide a comprehensive emissions inventory from onshore area sources, offshore oil and gas platforms, and onshore drilling rig activities.

In addition to compiling the emissions inventory, other objectives of this project were to identify the emission source types operating at oil and gas production sites, to develop a methodology for estimating area source emissions from oil and gas production sites based on the oil and gas produced at the county level, to develop survey materials that may be used to obtain detailed information needed to estimate emissions, and to identify the producers of oil and gas for each county. In conjunction with these activities, an emissions calculator was developed in Microsoft Excel that will allow TCEQ to update the emissions inventory for future years by providing updated county-level activity data. Finally, the emissions inventory was compiled into National Emissions Inventory Input Format (NIF) 3.0 text files for import into the Texas Air Emissions Repository (TexAER).

ERG was able to compile the 2008 area source emissions inventory from upstream onshore oil and gas production sites by obtaining both county-level activity data, and specific emissions and emission factor data for each source type. This data was obtained from a variety of sources, including existing databases (such as the Texas Railroad Commission (TRC) oil and gas production data), point source emissions inventory reports submitted to TCEQ (for dehydrators), vendor data (for compression engines and pumpjack engines), and published emission factor and activity data from the Houston Advanced Research Center (HARC), the Central Regional Air Planning Association (CENRAP), and the U.S. Environmental Protection Agency (EPA).

Table E-1 presents a state-wide summary of criteria pollutant (and total HAP) emissions by source category, and Table E-2 presents a summary of criteria pollutant (and total HAP) emissions for each county. As can be seen in these tables, emissions from area source upstream oil and gas production sites on a state-wide basis are significant with over 200,000 tons of NO_x, 1,500,000 tons of VOC, and 30,000 tons of HAPs emitted in 2008. The main source of NO_x

emissions are compressor engines, while the main source of VOC and HAP emissions are oil and condensate storage tanks.

It should be noted that the emission estimates provided in this report were based on available data and do not take into account more specific emission information such as county-specific gas composition data, or the extent that control devices that may be used on certain source types (such as well completions) to reduce emissions. More accurate emissions estimates would require a comprehensive survey of upstream oil and gas site operators to obtain information such as county-level gas composition data, quantification of the use of control devices, updated equipment profiles (such as the number and size of heater treaters used on a typical well pad), and updated equipment characteristics and counts.

Table E-1. State-wide Emissions Inventory for 2008 by Source Category

SCC	Source Category Description	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
2310000330	Artificial Lift	23,169.14	46,369.72	154.04	154.04	9.56	440.12	140.49
2310011020	Storage Tanks: Crude Oil						282,420.05	5,060.01
2310011100	Heater Treater	9,267.25	11,032.44	838.47	838.47	21.32	606.78	208.67
2310011201	Tank Truck/Railcar Loading: Crude Oil						26,810.72	479.91
2310011450	Wellhead						116,245.65	
2310011501	Fugitives: Connectors						2,956.39	
2310011502	Fugitives: Flanges						135.46	
2310011503	Fugitives: Open Ended Lines						605.72	
2310011504	Fugitives: Pumps						4,326.59	
2310011505	Fugitives: Valves						7,821.14	
2310011506	Fugitives: Other						12,480.55	
2310020600	Compressor Engines	133.77	255.90	13.58	13.58	0.21	81.40	29.00
2310021010	Storage Tanks: Condensate						864,087.90	17,281.71
2310021030	Tank Truck/Railcar Loading Condensate						7,235.50	144.71
2310021100	Gas Well Heaters	7,564.83	9,005.75	684.44	684.44	0.04	495.32	170.34
2310021101	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines <50 Hp	140.52	209.25	9.72	9.72	0.16	43.38	15.46
2310021102	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines 50 To 499 Hp	2,907.93	13,691.38	352.37	352.37	5.71	2,012.02	716.78
2310021203	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines 500+ Hp	14,746.41	8,801.63	76.95	76.95	15.94	3,817.42	2,337.58
2310021301	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines <50 Hp	93.37	1,175.69	3.86	3.86	0.25	5.61	5.50

Table E-1. State-wide Emissions Inventory for 2008 by Source Category (Cont.)

SCC	Source Category Description	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
2310021302	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50 To 499hp	38,988.69	86,462.54	226.24	226.24	14.83	1,487.26	1,451.93
2310021400	Gas Well Dehydrators	904.59	293.36				6,344.85	5,255.17
2310021402	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50-499hp W/ Nscr	767.55	468.45	35.02	35.02	2.05	17.73	17.46
2310021403	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 500+ Hp W/ Nscr	29,646.80	40,430.00	175.33	175.33	11.26	794.33	775.73
2310021501	Fugitives: Connectors						1,161.52	
2310021502	Fugitives: Flanges						1,199.68	
2310021503	Fugitives: Open Ended Lines						916.82	
2310021504	Fugitives: Pumps						476.31	
2310021505	Fugitives: Valves						7,387.52	
2310021506	Fugitives: Other						8,732.37	
2310021600	Gas Well Venting						8,601.78	
2310021700	Gas Well Completion: All Processes						10,139.56	
2310111700	Oil Well Completion: All Processes						19,425.44	
2310121401	Gas Well Pneumatic Pumps						169,209.86	
	Total:	**128,330.85**	**218,196.11**	**2,570.01**	**2,570.01**	**81.34**	**1,568,522.73**	**34,090.45**

Table E-2. State-wide Emissions Inventory for 2008 by County

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Anderson	241.28	444.72	5.31	5.31	0.16	2,858.24	52.77
Andrews	1,825.99	3,291.18	49.14	49.14	1.57	31,691.46	444.20
Angelina	161.97	311.11	2.15	2.15	0.08	629.30	25.94
Aransas	165.25	317.00	2.28	2.28	0.09	6,574.04	144.42
Archer	614.91	1,088.88	18.74	18.74	0.58	2,719.03	24.45
Armstrong	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Atascosa	321.56	578.81	8.71	8.71	0.27	2,237.28	31.44
Austin	127.18	237.83	2.42	2.42	0.07	2,040.58	43.74
Bailey	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bandera	0.21	0.37	0.01	0.01	0.00	5.14	0.03
Bastrop	74.21	128.49	2.56	2.56	0.06	1,286.18	16.32
Baylor	26.78	47.39	0.82	0.82	0.03	189.33	1.96
Bee	581.15	1,101.85	9.42	9.42	0.31	4,717.44	125.89
Bell	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bexar	531.99	941.46	16.28	16.28	0.51	2,120.86	7.60
Blanco	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Borden	166.31	300.48	4.40	4.40	0.14	4,107.39	62.92
Bosque	3.45	6.30	0.08	0.08	0.00	17.43	0.34
Bowie	5.13	9.25	0.14	0.14	0.00	148.70	2.69
Brazoria	207.73	199.95	6.59	6.59	0.28	14,003.43	292.15
Brazos	240.26	444.10	5.18	5.18	0.16	3,781.19	74.41
Brewster	0.00	0.00	0.00	0.00	0.00	5.88	0.00
Briscoe	0.00	0.00	0.00	0.00	0.00	12.33	0.01
Brooks	690.71	1,318.85	10.17	10.17	0.35	16,242.00	374.16
Brown	204.73	339.96	8.55	8.55	0.14	1,626.85	6.71
Burleson	366.21	669.08	8.80	8.80	0.28	3,881.39	67.20
Burnet	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Caldwell	676.24	1,197.43	20.61	20.61	0.64	3,452.64	22.69
Calhoun	189.99	360.25	3.07	3.07	0.10	7,473.42	160.35
Callahan	182.61	321.30	5.76	5.76	0.16	983.48	9.65
Cameron	1.68	3.12	0.03	0.03	0.00	10.26	0.20
Camp	30.41	55.01	0.79	0.79	0.03	259.21	4.96
Carson	569.73	1,021.51	15.74	15.74	0.41	1,954.76	34.12
Cass	54.95	98.13	1.55	1.55	0.04	662.46	11.89
Castro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chambers	84.76	94.63	2.75	2.75	0.11	4,424.08	90.13
Cherokee	364.58	682.18	6.78	6.78	0.18	2,911.32	72.93
Childress	1.69	2.99	0.05	0.05	0.00	57.40	0.71
Clay	231.82	409.65	7.14	7.14	0.21	1,476.89	16.60
Cochran	445.16	791.68	13.17	13.17	0.41	6,168.35	67.45
Coke	109.55	200.99	2.54	2.54	0.08	1,010.20	15.88
Coleman	173.73	295.58	6.51	6.51	0.13	1,363.81	9.92
Collin	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Collingsworth	50.04	76.34	2.77	2.77	0.02	742.63	2.58
Colorado	319.38	601.84	5.54	5.54	0.16	4,980.62	115.78
Comal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Comanche	34.22	53.57	1.76	1.76	0.02	438.42	1.97
Concho	72.58	128.12	2.23	2.23	0.06	821.04	9.65
Cooke	495.43	884.64	14.25	14.25	0.45	3,467.02	50.26
Coryell	0.00	0.00	0.00	0.00	0.00	3.13	0.00
Cottle	95.67	180.55	1.63	1.63	0.05	2,376.44	52.30
Crane	1,739.98	3,208.47	38.61	38.61	1.26	17,274.91	291.73
Crockett	2,274.88	4,015.15	68.61	68.61	1.15	28,501.91	414.45
Crosby	85.55	151.51	2.61	2.61	0.08	1,056.14	9.67

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Culberson	72.79	137.98	1.20	1.20	0.04	284.44	8.75
Dallam	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dallas	28.04	6.56	0.21	0.21	0.02	24.60	4.23
Dawson	275.48	492.78	7.84	7.84	0.25	5,344.51	72.02
Deaf Smith	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delta	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Denton	1,763.52	615.91	29.51	29.51	1.14	13,254.59	416.58
Dewitt	676.49	1,300.83	9.00	9.00	0.35	11,617.04	287.72
Dickens	49.70	88.22	1.49	1.49	0.05	1,446.43	20.78
Dimmit	197.89	353.20	5.65	5.65	0.15	2,515.16	31.86
Donley	0.53	0.77	0.03	0.03	0.00	15.82	0.17
Duval	1,111.17	2,101.02	18.70	18.70	0.63	12,897.27	314.00
Eastland	285.26	476.94	11.51	11.51	0.18	3,654.84	39.72
Ector	1,798.24	3,277.22	44.40	44.40	1.47	26,211.12	388.97
Edwards	270.78	492.35	6.60	6.60	0.13	1,377.01	25.49
El Paso	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ellis	51.17	13.49	0.47	0.47	0.04	52.43	7.56
Erath	161.14	295.43	3.68	3.68	0.07	1,556.95	32.84
Falls	4.01	7.09	0.12	0.12	0.00	21.49	0.09
Fannin	0.00	0.00	0.00	0.00	0.00	11.86	0.00
Fayette	356.62	659.40	7.64	7.64	0.23	5,607.61	115.67
Fisher	107.82	193.50	2.99	2.99	0.09	1,365.54	16.44
Floyd	0.42	0.75	0.01	0.01	0.00	2.97	0.03
Foard	27.94	43.90	1.42	1.42	0.01	414.38	2.57
Fort Bend	169.68	171.80	5.51	5.51	0.22	8,072.59	166.58
Franklin	69.40	127.99	1.52	1.52	0.05	1,389.52	28.31
Freestone	3,821.60	7,289.51	56.95	56.95	1.93	9,858.72	475.09

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Frio	139.12	246.28	4.21	4.21	0.12	1,393.74	14.40
Gaines	1,165.52	2,133.47	27.65	27.65	0.92	27,788.32	460.84
Galveston	86.46	76.28	2.61	2.61	0.12	17,475.45	358.12
Garza	445.72	790.41	13.45	13.45	0.42	6,133.80	63.01
Gillespie	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Glasscock	416.67	761.54	10.00	10.00	0.32	5,431.20	84.49
Goliad	731.21	1,386.08	11.85	11.85	0.37	7,851.72	199.63
Gonzales	51.40	92.76	1.37	1.37	0.04	578.12	8.62
Gray	825.55	1,440.69	27.11	27.11	0.64	4,163.88	45.84
Grayson	201.98	365.62	5.22	5.22	0.16	1,707.03	31.65
Gregg	1,423.90	2,592.32	34.92	34.92	1.00	10,980.44	227.68
Grimes	334.10	638.29	4.87	4.87	0.17	1,264.12	50.60
Guadalupe	402.11	711.73	12.29	12.29	0.38	2,576.45	22.66
Hale	62.99	114.67	1.57	1.57	0.05	2,698.37	46.20
Hall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hamilton	3.12	5.33	0.11	0.11	0.00	36.47	0.47
Hansford	377.68	676.20	10.32	10.32	0.17	2,601.06	43.25
Hardeman	52.13	92.68	1.54	1.54	0.05	1,230.36	19.89
Hardin	258.68	348.83	7.85	7.85	0.30	22,648.65	447.94
Harris	176.00	181.67	5.65	5.65	0.23	8,801.29	184.44
Harrison	1,879.59	3,514.48	35.19	35.19	0.93	25,383.90	583.58
Hartley	39.06	70.27	1.04	1.04	0.02	399.51	6.56
Haskell	53.83	95.30	1.64	1.64	0.05	443.81	5.44
Hays	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hemphill	2,092.63	3,936.72	37.08	37.08	1.03	32,774.76	754.74
Henderson	453.75	854.13	7.99	7.99	0.24	2,535.12	73.92
Hidalgo	3,264.69	6,276.64	43.49	43.49	1.68	56,554.95	1,407.72

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Hill	308.20	597.97	3.53	3.53	0.16	233.61	34.41
Hockley	1,004.10	1,795.93	28.58	28.58	0.91	22,011.88	308.12
Hood	926.80	1,777.59	12.89	12.89	0.47	9,914.41	269.97
Hopkins	20.84	37.79	0.53	0.53	0.02	298.78	5.06
Houston	164.62	308.00	3.11	3.11	0.10	1,587.91	35.84
Howard	803.87	1,436.74	23.00	23.00	0.73	9,904.95	107.63
Hudspeth	0.12	0.17	0.01	0.01	0.00	3.29	0.03
Hunt	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hutchinson	903.43	1,601.32	27.09	27.09	0.72	4,039.66	49.29
Irion	531.51	961.89	13.77	13.77	0.40	5,877.27	82.51
Jack	646.65	1,121.02	21.80	21.80	0.42	6,701.91	92.20
Jackson	303.15	569.09	5.55	5.55	0.17	9,879.64	204.59
Jasper	205.58	394.00	2.87	2.87	0.11	6,405.78	143.58
Jeff Davis	0.00	0.00	0.00	0.00	0.00	1.29	0.03
Jefferson	287.19	182.64	8.05	8.05	0.46	55,659.21	1,163.27
Jim Hogg	266.50	500.41	4.83	4.83	0.14	4,021.10	92.33
Jim Wells	127.37	226.90	3.61	3.61	0.06	1,576.61	26.20
Johnson	4,495.48	1,157.96	43.01	43.01	3.19	5,209.18	684.81
Jones	167.32	296.69	5.05	5.05	0.16	1,277.91	14.79
Karnes	171.32	323.25	2.95	2.95	0.10	3,454.12	76.12
Kaufman	4.50	7.85	0.14	0.14	0.00	62.82	1.05
Kendall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kenedy	665.44	1,286.34	8.13	8.13	0.35	4,087.71	143.43
Kent	203.51	375.70	4.48	4.48	0.16	4,304.19	73.92
Kerr	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kimble	2.94	4.50	0.16	0.16	0.00	41.29	0.17
King	112.59	198.82	3.47	3.47	0.10	2,010.47	35.20

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Kinney	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kleberg	494.21	948.96	6.71	6.71	0.25	8,845.84	217.77
Knox	46.18	81.72	1.41	1.41	0.04	354.81	4.00
La Salle	259.22	470.95	6.38	6.38	0.13	4,078.69	76.37
Lamar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lamb	15.10	27.13	0.42	0.42	0.01	686.85	11.01
Lampasas	0.16	0.20	0.01	0.01	0.00	4.24	0.00
Lavaca	924.67	1,764.89	13.68	13.68	0.47	12,277.67	311.64
Lee	307.30	564.26	7.08	7.08	0.23	2,650.76	49.84
Leon	1,079.72	2,070.29	15.01	15.01	0.58	5,733.49	197.49
Liberty	331.40	341.24	9.92	9.92	0.45	27,316.75	570.30
Limestone	1,393.87	2,655.14	21.17	21.17	0.71	4,377.56	180.91
Lipscomb	1,125.34	2,104.13	21.36	21.36	0.58	17,104.94	381.52
Live Oak	378.16	709.70	6.91	6.91	0.20	6,807.99	149.58
Llano	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Loving	1,567.71	3,023.10	20.15	20.15	0.89	6,348.57	251.69
Lubbock	89.19	158.04	2.71	2.71	0.08	1,825.32	23.15
Lynn	18.52	33.00	0.54	0.54	0.02	350.40	4.52
Madison	117.26	216.26	2.56	2.56	0.07	1,290.52	26.07
Marion	96.78	174.38	2.56	2.56	0.06	1,407.02	25.69
Martin	596.73	1,088.02	14.69	14.69	0.49	10,928.66	168.72
Mason	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Matagorda	609.79	1,168.96	8.47	8.47	0.32	19,098.24	428.64
Maverick	182.47	323.89	5.42	5.42	0.15	3,715.58	42.08
McCulloch	14.65	25.47	0.50	0.50	0.01	109.65	1.15
McLennan	8.65	15.30	0.26	0.26	0.01	27.43	0.12
McMullen	493.90	900.42	11.92	11.92	0.29	6,027.42	110.63

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Medina	275.72	487.25	8.50	8.50	0.26	1,235.77	4.54
Menard	27.00	47.52	0.85	0.85	0.02	266.84	2.69
Midland	1,610.04	2,951.97	37.75	37.75	1.27	20,938.23	333.93
Milam	218.91	387.83	6.65	6.65	0.21	1,216.87	9.32
Mills	0.36	0.51	0.02	0.02	0.00	6.38	0.02
Mitchell	502.49	890.13	15.28	15.28	0.48	6,645.63	65.00
Montague	551.48	987.06	15.59	15.59	0.49	3,448.92	48.39
Montgomery	73.56	81.80	2.86	2.86	0.08	2,890.56	54.67
Moore	744.02	1,343.19	19.29	19.29	0.40	3,502.87	63.64
Morris	0.21	0.37	0.01	0.01	0.00	2.01	0.03
Motley	3.80	6.72	0.12	0.12	0.00	52.75	0.49
Nacogdoches	1,527.76	2,897.04	24.29	24.29	0.77	12,723.39	353.60
Navarro	170.24	301.61	5.16	5.16	0.16	1,444.51	18.73
Newton	78.50	145.69	1.63	1.63	0.05	1,601.94	31.72
Nolan	133.50	240.21	3.63	3.63	0.11	1,931.63	25.88
Nueces	605.47	1,127.23	11.99	11.99	0.31	15,740.17	332.51
Ochiltree	561.88	1,020.35	13.94	13.94	0.31	5,760.68	108.67
Oldham	5.68	10.02	0.17	0.17	0.00	247.24	3.74
Orange	67.79	71.25	2.06	2.06	0.09	8,467.82	172.90
Palo Pinto	455.72	785.82	15.70	15.70	0.21	7,033.45	105.26
Panola	3,784.21	7,052.88	73.18	73.18	1.82	50,362.96	1,170.88
Parker	1,225.52	407.43	19.49	19.49	0.80	9,840.76	290.06
Parmer	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pecos	4,534.56	8,670.50	66.30	66.30	2.63	21,760.89	703.44
Polk	415.68	797.76	5.69	5.69	0.22	29,650.93	625.12
Potter	350.79	632.33	9.25	9.25	0.21	1,799.21	27.27
Presidio	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Rains	59.61	115.43	0.71	0.71	0.03	38.47	6.62
Randall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reagan	1,209.82	2,204.56	29.89	29.89	0.99	11,808.61	158.58
Real	1.91	3.34	0.06	0.06	0.00	16.74	0.15
Red River	9.57	16.96	0.29	0.29	0.01	159.73	2.26
Reeves	575.50	1,077.94	10.88	10.88	0.36	3,146.28	72.34
Refugio	652.55	1,218.19	12.72	12.72	0.40	9,671.07	197.77
Roberts	881.18	1,659.43	15.47	15.47	0.45	15,296.54	346.65
Robertson	3,591.03	6,960.37	41.87	41.87	1.90	4,202.14	427.68
Rockwall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Runnels	145.66	262.06	3.96	3.96	0.12	1,177.54	15.82
Rusk	2,394.04	4,447.78	48.27	48.27	1.34	26,428.99	597.16
Sabine	2.04	3.67	0.06	0.06	0.00	19.20	0.14
San Augustine	159.66	309.99	1.77	1.77	0.09	452.69	23.22
San Jacinto	182.43	350.28	2.47	2.47	0.09	6,462.64	144.35
San Patricio	303.08	570.53	5.36	5.36	0.16	12,721.07	267.75
San Saba	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Schleicher	297.16	521.39	9.30	9.30	0.15	3,975.13	56.43
Scurry	920.14	1,696.28	20.52	20.52	0.72	16,745.60	282.63
Shackelford	446.66	787.83	13.87	13.87	0.39	2,584.60	27.41
Shelby	788.21	1,506.84	11.24	11.24	0.40	4,681.48	153.59
Sherman	382.36	689.34	9.93	9.93	0.17	2,226.58	38.78
Smith	600.16	1,117.21	11.83	11.83	0.32	6,759.09	157.15
Somervell	69.05	132.73	0.93	0.93	0.04	261.32	10.71
Starr	1,801.98	3,435.69	27.08	27.08	0.92	39,905.70	922.75
Stephens	548.00	962.55	17.22	17.22	0.36	6,028.28	86.04
Sterling	507.62	898.57	15.24	15.24	0.35	5,045.87	54.84

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Stonewall	125.21	222.61	3.72	3.72	0.12	1,647.78	17.01
Sutton	1,536.07	2,640.40	53.45	53.45	0.57	14,703.05	158.36
Swisher	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tarrant	4,070.91	1,055.42	39.54	39.54	2.88	4,929.92	620.02
Taylor	92.16	163.25	2.80	2.80	0.09	693.08	8.42
Terrell	890.56	1,697.22	13.46	13.46	0.45	4,554.08	153.52
Terry	217.93	388.12	6.39	6.39	0.20	5,118.11	70.81
Throckmorton	221.50	393.95	6.55	6.55	0.20	1,242.06	15.21
Titus	42.19	74.68	1.29	1.29	0.04	506.68	8.03
Tom Green	170.07	304.64	4.76	4.76	0.14	1,945.37	23.40
Travis	3.37	5.97	0.10	0.10	0.00	14.43	0.07
Trinity	10.94	19.88	0.27	0.27	0.01	193.38	3.42
Tyler	463.76	896.18	5.69	5.69	0.25	57,953.39	1,201.05
Upshur	604.48	1,126.42	11.73	11.73	0.30	10,582.53	238.20
Upton	1,602.98	2,998.03	30.90	30.90	1.09	32,833.54	647.89
Uvalde	0.20	0.26	0.02	0.02	0.00	4.37	0.01
Val Verde	210.53	394.38	3.90	3.90	0.10	620.76	21.64
Van Zandt	193.81	352.82	4.81	4.81	0.15	1,204.59	23.27
Victoria	287.47	535.68	5.67	5.67	0.16	3,296.01	69.83
Walker	13.49	24.74	0.31	0.31	0.01	85.26	1.73
Waller	88.01	106.67	2.83	2.83	0.11	2,859.24	56.46
Ward	1,288.64	2,381.97	28.00	28.00	0.94	9,588.88	230.25
Washington	256.76	485.36	4.31	4.31	0.14	2,513.65	64.54
Webb	3,123.82	5,806.41	62.66	62.66	1.48	28,275.41	664.71
Wharton	692.11	1,309.84	11.43	11.43	0.37	15,986.48	354.54
Wheeler	2,223.92	4,231.74	34.40	34.40	1.15	40,674.02	955.94
Wichita	1,185.96	2,099.33	36.23	36.23	1.13	5,040.04	46.60

Table E-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Wilbarger	174.53	308.95	5.33	5.33	0.17	1,147.90	13.03
Willacy	353.53	681.05	4.59	4.59	0.19	8,274.58	193.92
Williamson	9.07	16.05	0.28	0.28	0.01	53.29	0.33
Wilson	129.98	230.01	3.98	3.98	0.12	757.55	6.10
Winkler	917.14	1,698.44	19.52	19.52	0.63	7,815.47	141.18
Wise	2,749.59	5,099.17	55.75	55.75	1.35	24,225.59	597.53
Wood	239.16	438.82	5.52	5.52	0.18	4,200.35	82.03
Yoakum	1,074.18	1,960.14	26.21	26.21	0.88	25,649.46	414.59
Young	556.32	978.60	17.57	17.57	0.50	3,394.26	35.11
Zapata	4,438.24	8,472.07	65.54	65.54	2.24	13,384.86	594.31
Zavala	64.75	114.70	1.94	1.94	0.05	1,016.76	14.24
Total:	**128,330.85**	**218,196.11**	**2,570.01**	**2,570.01**	**81.34**	**1,568,522.73**	**34,090.45**

1.0 INTRODUCTION

This study was implemented for the Texas Commission on Environmental Quality (TCEQ) to identify and characterize area source emissions from upstream oil and gas production sites that operated in Texas in 2008, and to provide county level emission estimates for each of these source types.

This study was divided into four primary technical work tasks:

- Identification and review of existing studies pertaining to estimating emissions from oil and gas production sites and recommendation of a preferred emission estimation approach for each identified emissions source type;
- Development of survey materials that may be used to obtain detailed information needed to estimate emissions, and identification of the producers of oil and gas for each county;
- Development of a methodology and calculator to estimate county-level emissions from each identified source type; and
- Performance of emissions estimation calculations for a 2008 base year, including the preparation of emissions inventory calculation spreadsheets (including activity data and emission factors) and documentation of data, procedures, and results in a final project report. Additionally, the final emissions inventory was imported into National Emissions Inventory Input Format (NIF) 3.0 text files for import into the Texas Air Emissions Repository (TexAER).

This project required compilation of data for each emission source type found at upstream oil and gas production sites. Table 1-1 presents a list of each source type, including their associated Source Classification Code (SCC).

Table 1-1. Upstream Oil and Gas Production Source Types

SCC	Source Category Description
2310021101	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines <50 Hp
2310021102	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines 50 TO 499 Hp
2310020600	Natural Gas Fired 2-Cycle Rich Burn Compressor Engines
2310021203	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines 500+ Hp
2310021301	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines <50 Hp
2310021302	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50 TO 499 Hp
2310021402	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50-499 Hp W/ NSCR
2310021403	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 500+ Hp W/ NSCR
2310000330	Oil and Gas Exploration and Production Artificial Lift Engines
2310021400	Dehydrators
2310011020	Oil Storage Tanks

Table 1-1. Upstream Oil and Gas Production Source Types (Cont.)

SCC	Source Category Description
2310021010	Condensate Storage Tanks
2310011201	Oil Loading
2310021030	Condensate Loading
2310111700	Oil Well Completions
2310021700	Gas Well Completions
2310011450	Oil Wellhead Blowdowns
2310021600	Gas Wellhead Blowdowns
2310121401	Pneumatic Devices
2310011505	Fugitives - Oil Well Valves
2310011504	Fugitives - Oil Well Pumps
2310011506	Fugitives - Oil Wells Other
2310011501	Fugitives - Oil Well Connectors
2310011502	Fugitives - Oil Well Flanges
2310011503	Fugitives - Oil Well Open Ended Lines
2310021505	Fugitives - Gas Well Valves
2310021504	Fugitives - Gas Well Pumps
2310021506	Fugitives - Gas Wells Other
2310021501	Fugitives - Gas Well Connectors
2310021502	Fugitives - Gas Well Flanges
2310021503	Fugitives - Gas Well Open Ended Lines
2310011100	Heaters - Oil Wells
2310021100	Heaters - Gas Wells

Section 2 of this report provides a summary of the literature review task undertaken to identify existing studies pertaining to oil and gas production area sources. Section 3 provides a summary of the efforts implemented to identify oil and gas source operators and owners in each county, and the development of survey materials that may be used to obtain detailed information needed to estimate emissions. Section 4 presents detailed information on the emissions calculation method used for each category, including a discussion of all variables used in the emissions calculation and how data for each variable were obtained. The quantitative results of this project are presented in Section 5, discussion of preparation of TexAER input files is provided in Section 6, conclusions and recommendations based on the results of this project are presented in Section 7, and Section 8 provides a reference list of information sources used to prepare this report and the emissions inventory.

Table 1-2 presents a state-wide summary of criteria pollutant (and total HAP) emissions by source category, and Table 1-3 presents a summary of criteria pollutant (and total HAP) emissions for each county. As can be seen in these tables, emissions in 2008 from this area source category on a state-wide basis are significant with over 200,000 tons of NO_x, 1,500,000 tons of VOC, and 30,000 tons of HAP. The main source of NO_x emissions are compressor engines, while the main source of VOC and HAP emissions are oil and condensate storage tanks.

Table 1-2. State-wide Emissions Inventory for 2008 by Source Category

SCC	Source Category Description	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
2310000330	Artificial Lift	23,169.14	46,369.72	154.04	154.04	9.56	440.12	140.49
2310011020	Storage Tanks: Crude Oil						282,420.05	5,060.01
2310011100	Heater Treater	9,267.25	11,032.44	838.47	838.47	21.32	606.78	208.67
2310011201	Tank Truck/Railcar Loading: Crude Oil						26,810.72	479.91
2310011450	Wellhead						116,245.65	
2310011501	Fugitives: Connectors						2,956.39	
2310011502	Fugitives: Flanges						135.46	
2310011503	Fugitives: Open Ended Lines						605.72	
2310011504	Fugitives: Pumps						4,326.59	
2310011505	Fugitives: Valves						7,821.14	
2310011506	Fugitives: Other						12,480.55	
2310020600	Compressor Engines	133.77	255.90	13.58	13.58	0.21	81.40	29.00
2310021010	Storage Tanks: Condensate						864,087.90	17,281.71
2310021030	Tank Truck/Railcar Loading Condensate						7,235.50	144.71
2310021100	Gas Well Heaters	7,564.83	9,005.75	684.44	684.44	0.04	495.32	170.34
2310021101	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines <50 Hp	140.52	209.25	9.72	9.72	0.16	43.38	15.46
2310021102	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines 50 To 499 Hp	2,907.93	13,691.38	352.37	352.37	5.71	2,012.02	716.78
2310021203	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines 500+ Hp	14,746.41	8,801.63	76.95	76.95	15.94	3,817.42	2,337.58
2310021301	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines <50 Hp	93.37	1,175.69	3.86	3.86	0.25	5.61	5.50

Table 1-2. State-wide Emissions Inventory for 2008 by Source Category (Cont.)

SCC	Source Category Description	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
2310021302	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50 To 499hp	38,988.69	86,462.54	226.24	226.24	14.83	1,487.26	1,451.93
2310021400	Gas Well Dehydrators	904.59	293.36				6,344.85	5,255.17
2310021402	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50-499hp W/ Nscr	767.55	468.45	35.02	35.02	2.05	17.73	17.46
2310021403	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 500+ Hp W/ Nscr	29,646.80	40,430.00	175.33	175.33	11.26	794.33	775.73
2310021501	Fugitives: Connectors						1,161.52	
2310021502	Fugitives: Flanges						1,199.68	
2310021503	Fugitives: Open Ended Lines						916.82	
2310021504	Fugitives: Pumps						476.31	
2310021505	Fugitives: Valves						7,387.52	
2310021506	Fugitives: Other						8,732.37	
2310021600	Gas Well Venting						8,601.78	
2310021700	Gas Well Completion: All Processes						10,139.56	
2310111700	Oil Well Completion: All Processes						19,425.44	
2310121401	Gas Well Pneumatic Pumps						169,209.86	
	Total:	**128,330.85**	**218,196.11**	**2,570.01**	**2,570.01**	**81.34**	**1,568,522.73**	**34,090.45**

Table 1-3. State-wide Emissions Inventory for 2008 by County

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Anderson	241.28	444.72	5.31	5.31	0.16	2,858.24	52.77
Andrews	1,825.99	3,291.18	49.14	49.14	1.57	31,691.46	444.20
Angelina	161.97	311.11	2.15	2.15	0.08	629.30	25.94
Aransas	165.25	317.00	2.28	2.28	0.09	6,574.04	144.42
Archer	614.91	1,088.88	18.74	18.74	0.58	2,719.03	24.45
Armstrong	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Atascosa	321.56	578.81	8.71	8.71	0.27	2,237.28	31.44
Austin	127.18	237.83	2.42	2.42	0.07	2,040.58	43.74
Bailey	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bandera	0.21	0.37	0.01	0.01	0.00	5.14	0.03
Bastrop	74.21	128.49	2.56	2.56	0.06	1,286.18	16.32
Baylor	26.78	47.39	0.82	0.82	0.03	189.33	1.96
Bee	581.15	1,101.85	9.42	9.42	0.31	4,717.44	125.89
Bell	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bexar	531.99	941.46	16.28	16.28	0.51	2,120.86	7.60
Blanco	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Borden	166.31	300.48	4.40	4.40	0.14	4,107.39	62.92
Bosque	3.45	6.30	0.08	0.08	0.00	17.43	0.34
Bowie	5.13	9.25	0.14	0.14	0.00	148.70	2.69
Brazoria	207.73	199.95	6.59	6.59	0.28	14,003.43	292.15
Brazos	240.26	444.10	5.18	5.18	0.16	3,781.19	74.41
Brewster	0.00	0.00	0.00	0.00	0.00	5.88	0.00
Briscoe	0.00	0.00	0.00	0.00	0.00	12.33	0.01
Brooks	690.71	1,318.85	10.17	10.17	0.35	16,242.00	374.16
Brown	204.73	339.96	8.55	8.55	0.14	1,626.85	6.71
Burleson	366.21	669.08	8.80	8.80	0.28	3,881.39	67.20

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Burnet	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Caldwell	676.24	1,197.43	20.61	20.61	0.64	3,452.64	22.69
Calhoun	189.99	360.25	3.07	3.07	0.10	7,473.42	160.35
Callahan	182.61	321.30	5.76	5.76	0.16	983.48	9.65
Cameron	1.68	3.12	0.03	0.03	0.00	10.26	0.20
Camp	30.41	55.01	0.79	0.79	0.03	259.21	4.96
Carson	569.73	1,021.51	15.74	15.74	0.41	1,954.76	34.12
Cass	54.95	98.13	1.55	1.55	0.04	662.46	11.89
Castro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chambers	84.76	94.63	2.75	2.75	0.11	4,424.08	90.13
Cherokee	364.58	682.18	6.78	6.78	0.18	2,911.32	72.93
Childress	1.69	2.99	0.05	0.05	0.00	57.40	0.71
Clay	231.82	409.65	7.14	7.14	0.21	1,476.89	16.60
Cochran	445.16	791.68	13.17	13.17	0.41	6,168.35	67.45
Coke	109.55	200.99	2.54	2.54	0.08	1,010.20	15.88
Coleman	173.73	295.58	6.51	6.51	0.13	1,363.81	9.92
Collin	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Collingsworth	50.04	76.34	2.77	2.77	0.02	742.63	2.58
Colorado	319.38	601.84	5.54	5.54	0.16	4,980.62	115.78
Comal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Comanche	34.22	53.57	1.76	1.76	0.02	438.42	1.97
Concho	72.58	128.12	2.23	2.23	0.06	821.04	9.65
Cooke	495.43	884.64	14.25	14.25	0.45	3,467.02	50.26
Coryell	0.00	0.00	0.00	0.00	0.00	3.13	0.00
Cottle	95.67	180.55	1.63	1.63	0.05	2,376.44	52.30
Crane	1,739.98	3,208.47	38.61	38.61	1.26	17,274.91	291.73

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Crockett	2,274.88	4,015.15	68.61	68.61	1.15	28,501.91	414.45
Crosby	85.55	151.51	2.61	2.61	0.08	1,056.14	9.67
Culberson	72.79	137.98	1.20	1.20	0.04	284.44	8.75
Dallam	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dallas	28.04	6.56	0.21	0.21	0.02	24.60	4.23
Dawson	275.48	492.78	7.84	7.84	0.25	5,344.51	72.02
Deaf Smith	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delta	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Denton	1,763.52	615.91	29.51	29.51	1.14	13,254.59	416.58
Dewitt	676.49	1,300.83	9.00	9.00	0.35	11,617.04	287.72
Dickens	49.70	88.22	1.49	1.49	0.05	1,446.43	20.78
Dimmit	197.89	353.20	5.65	5.65	0.15	2,515.16	31.86
Donley	0.53	0.77	0.03	0.03	0.00	15.82	0.17
Duval	1,111.17	2,101.02	18.70	18.70	0.63	12,897.27	314.00
Eastland	285.26	476.94	11.51	11.51	0.18	3,654.84	39.72
Ector	1,798.24	3,277.22	44.40	44.40	1.47	26,211.12	388.97
Edwards	270.78	492.35	6.60	6.60	0.13	1,377.01	25.49
El Paso	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ellis	51.17	13.49	0.47	0.47	0.04	52.43	7.56
Erath	161.14	295.43	3.68	3.68	0.07	1,556.95	32.84
Falls	4.01	7.09	0.12	0.12	0.00	21.49	0.09
Fannin	0.00	0.00	0.00	0.00	0.00	11.86	0.00
Fayette	356.62	659.40	7.64	7.64	0.23	5,607.61	115.67
Fisher	107.82	193.50	2.99	2.99	0.09	1,365.54	16.44
Floyd	0.42	0.75	0.01	0.01	0.00	2.97	0.03
Foard	27.94	43.90	1.42	1.42	0.01	414.38	2.57

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Fort Bend	169.68	171.80	5.51	5.51	0.22	8,072.59	166.58
Franklin	69.40	127.99	1.52	1.52	0.05	1,389.52	28.31
Freestone	3,821.60	7,289.51	56.95	56.95	1.93	9,858.72	475.09
Frio	139.12	246.28	4.21	4.21	0.12	1,393.74	14.40
Gaines	1,165.52	2,133.47	27.65	27.65	0.92	27,788.32	460.84
Galveston	86.46	76.28	2.61	2.61	0.12	17,475.45	358.12
Garza	445.72	790.41	13.45	13.45	0.42	6,133.80	63.01
Gillespie	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Glasscock	416.67	761.54	10.00	10.00	0.32	5,431.20	84.49
Goliad	731.21	1,386.08	11.85	11.85	0.37	7,851.72	199.63
Gonzales	51.40	92.76	1.37	1.37	0.04	578.12	8.62
Gray	825.55	1,440.69	27.11	27.11	0.64	4,163.88	45.84
Grayson	201.98	365.62	5.22	5.22	0.16	1,707.03	31.65
Gregg	1,423.90	2,592.32	34.92	34.92	1.00	10,980.44	227.68
Grimes	334.10	638.29	4.87	4.87	0.17	1,264.12	50.60
Guadalupe	402.11	711.73	12.29	12.29	0.38	2,576.45	22.66
Hale	62.99	114.67	1.57	1.57	0.05	2,698.37	46.20
Hall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hamilton	3.12	5.33	0.11	0.11	0.00	36.47	0.47
Hansford	377.68	676.20	10.32	10.32	0.17	2,601.06	43.25
Hardeman	52.13	92.68	1.54	1.54	0.05	1,230.36	19.89
Hardin	258.68	348.83	7.85	7.85	0.30	22,648.65	447.94
Harris	176.00	181.67	5.65	5.65	0.23	8,801.29	184.44
Harrison	1,879.59	3,514.48	35.19	35.19	0.93	25,383.90	583.58
Hartley	39.06	70.27	1.04	1.04	0.02	399.51	6.56
Haskell	53.83	95.30	1.64	1.64	0.05	443.81	5.44

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Hays	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hemphill	2,092.63	3,936.72	37.08	37.08	1.03	32,774.76	754.74
Henderson	453.75	854.13	7.99	7.99	0.24	2,535.12	73.92
Hidalgo	3,264.69	6,276.64	43.49	43.49	1.68	56,554.95	1,407.72
Hill	308.20	597.97	3.53	3.53	0.16	233.61	34.41
Hockley	1,004.10	1,795.93	28.58	28.58	0.91	22,011.88	308.12
Hood	926.80	1,777.59	12.89	12.89	0.47	9,914.41	269.97
Hopkins	20.84	37.79	0.53	0.53	0.02	298.78	5.06
Houston	164.62	308.00	3.11	3.11	0.10	1,587.91	35.84
Howard	803.87	1,436.74	23.00	23.00	0.73	9,904.95	107.63
Hudspeth	0.12	0.17	0.01	0.01	0.00	3.29	0.03
Hunt	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hutchinson	903.43	1,601.32	27.09	27.09	0.72	4,039.66	49.29
Irion	531.51	961.89	13.77	13.77	0.40	5,877.27	82.51
Jack	646.65	1,121.02	21.80	21.80	0.42	6,701.91	92.20
Jackson	303.15	569.09	5.55	5.55	0.17	9,879.64	204.59
Jasper	205.58	394.00	2.87	2.87	0.11	6,405.78	143.58
Jeff Davis	0.00	0.00	0.00	0.00	0.00	1.29	0.03
Jefferson	287.19	182.64	8.05	8.05	0.46	55,659.21	1,163.27
Jim Hogg	266.50	500.41	4.83	4.83	0.14	4,021.10	92.33
Jim Wells	127.37	226.90	3.61	3.61	0.06	1,576.61	26.20
Johnson	4,495.48	1,157.96	43.01	43.01	3.19	5,209.18	684.81
Jones	167.32	296.69	5.05	5.05	0.16	1,277.91	14.79
Karnes	171.32	323.25	2.95	2.95	0.10	3,454.12	76.12
Kaufman	4.50	7.85	0.14	0.14	0.00	62.82	1.05
Kendall	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Kenedy	665.44	1,286.34	8.13	8.13	0.35	4,087.71	143.43
Kent	203.51	375.70	4.48	4.48	0.16	4,304.19	73.92
Kerr	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kimble	2.94	4.50	0.16	0.16	0.00	41.29	0.17
King	112.59	198.82	3.47	3.47	0.10	2,010.47	35.20
Kinney	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kleberg	494.21	948.96	6.71	6.71	0.25	8,845.84	217.77
Knox	46.18	81.72	1.41	1.41	0.04	354.81	4.00
La Salle	259.22	470.95	6.38	6.38	0.13	4,078.69	76.37
Lamar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lamb	15.10	27.13	0.42	0.42	0.01	686.85	11.01
Lampasas	0.16	0.20	0.01	0.01	0.00	4.24	0.00
Lavaca	924.67	1,764.89	13.68	13.68	0.47	12,277.67	311.64
Lee	307.30	564.26	7.08	7.08	0.23	2,650.76	49.84
Leon	1,079.72	2,070.29	15.01	15.01	0.58	5,733.49	197.49
Liberty	331.40	341.24	9.92	9.92	0.45	27,316.75	570.30
Limestone	1,393.87	2,655.14	21.17	21.17	0.71	4,377.56	180.91
Lipscomb	1,125.34	2,104.13	21.36	21.36	0.58	17,104.94	381.52
Live Oak	378.16	709.70	6.91	6.91	0.20	6,807.99	149.58
Llano	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Loving	1,567.71	3,023.10	20.15	20.15	0.89	6,348.57	251.69
Lubbock	89.19	158.04	2.71	2.71	0.08	1,825.32	23.15
Lynn	18.52	33.00	0.54	0.54	0.02	350.40	4.52
Madison	117.26	216.26	2.56	2.56	0.07	1,290.52	26.07
Marion	96.78	174.38	2.56	2.56	0.06	1,407.02	25.69
Martin	596.73	1,088.02	14.69	14.69	0.49	10,928.66	168.72

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Mason	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Matagorda	609.79	1,168.96	8.47	8.47	0.32	19,098.24	428.64
Maverick	182.47	323.89	5.42	5.42	0.15	3,715.58	42.08
McCulloch	14.65	25.47	0.50	0.50	0.01	109.65	1.15
McLennan	8.65	15.30	0.26	0.26	0.01	27.43	0.12
McMullen	493.90	900.42	11.92	11.92	0.29	6,027.42	110.63
Medina	275.72	487.25	8.50	8.50	0.26	1,235.77	4.54
Menard	27.00	47.52	0.85	0.85	0.02	266.84	2.69
Midland	1,610.04	2,951.97	37.75	37.75	1.27	20,938.23	333.93
Milam	218.91	387.83	6.65	6.65	0.21	1,216.87	9.32
Mills	0.36	0.51	0.02	0.02	0.00	6.38	0.02
Mitchell	502.49	890.13	15.28	15.28	0.48	6,645.63	65.00
Montague	551.48	987.06	15.59	15.59	0.49	3,448.92	48.39
Montgomery	73.56	81.80	2.86	2.86	0.08	2,890.56	54.67
Moore	744.02	1,343.19	19.29	19.29	0.40	3,502.87	63.64
Morris	0.21	0.37	0.01	0.01	0.00	2.01	0.03
Motley	3.80	6.72	0.12	0.12	0.00	52.75	0.49
Nacogdoches	1,527.76	2,897.04	24.29	24.29	0.77	12,723.39	353.60
Navarro	170.24	301.61	5.16	5.16	0.16	1,444.51	18.73
Newton	78.50	145.69	1.63	1.63	0.05	1,601.94	31.72
Nolan	133.50	240.21	3.63	3.63	0.11	1,931.63	25.88
Nueces	605.47	1,127.23	11.99	11.99	0.31	15,740.17	332.51
Ochiltree	561.88	1,020.35	13.94	13.94	0.31	5,760.68	108.67
Oldham	5.68	10.02	0.17	0.17	0.00	247.24	3.74
Orange	67.79	71.25	2.06	2.06	0.09	8,467.82	172.90
Palo Pinto	455.72	785.82	15.70	15.70	0.21	7,033.45	105.26

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Panola	3,784.21	7,052.88	73.18	73.18	1.82	50,362.96	1,170.88
Parker	1,225.52	407.43	19.49	19.49	0.80	9,840.76	290.06
Parmer	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pecos	4,534.56	8,670.50	66.30	66.30	2.63	21,760.89	703.44
Polk	415.68	797.76	5.69	5.69	0.22	29,650.93	625.12
Potter	350.79	632.33	9.25	9.25	0.21	1,799.21	27.27
Presidio	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rains	59.61	115.43	0.71	0.71	0.03	38.47	6.62
Randall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reagan	1,209.82	2,204.56	29.89	29.89	0.99	11,808.61	158.58
Real	1.91	3.34	0.06	0.06	0.00	16.74	0.15
Red River	9.57	16.96	0.29	0.29	0.01	159.73	2.26
Reeves	575.50	1,077.94	10.88	10.88	0.36	3,146.28	72.34
Refugio	652.55	1,218.19	12.72	12.72	0.40	9,671.07	197.77
Roberts	881.18	1,659.43	15.47	15.47	0.45	15,296.54	346.65
Robertson	3,591.03	6,960.37	41.87	41.87	1.90	4,202.14	427.68
Rockwall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Runnels	145.66	262.06	3.96	3.96	0.12	1,177.54	15.82
Rusk	2,394.04	4,447.78	48.27	48.27	1.34	26,428.99	597.16
Sabine	2.04	3.67	0.06	0.06	0.00	19.20	0.14
San Augustine	159.66	309.99	1.77	1.77	0.09	452.69	23.22
San Jacinto	182.43	350.28	2.47	2.47	0.09	6,462.64	144.35
San Patricio	303.08	570.53	5.36	5.36	0.16	12,721.07	267.75
San Saba	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Schleicher	297.16	521.39	9.30	9.30	0.15	3,975.13	56.43
Scurry	920.14	1,696.28	20.52	20.52	0.72	16,745.60	282.63

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Shackelford	446.66	787.83	13.87	13.87	0.39	2,584.60	27.41
Shelby	788.21	1,506.84	11.24	11.24	0.40	4,681.48	153.59
Sherman	382.36	689.34	9.93	9.93	0.17	2,226.58	38.78
Smith	600.16	1,117.21	11.83	11.83	0.32	6,759.09	157.15
Somervell	69.05	132.73	0.93	0.93	0.04	261.32	10.71
Starr	1,801.98	3,435.69	27.08	27.08	0.92	39,905.70	922.75
Stephens	548.00	962.55	17.22	17.22	0.36	6,028.28	86.04
Sterling	507.62	898.57	15.24	15.24	0.35	5,045.87	54.84
Stonewall	125.21	222.61	3.72	3.72	0.12	1,647.78	17.01
Sutton	1,536.07	2,640.40	53.45	53.45	0.57	14,703.05	158.36
Swisher	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tarrant	4,070.91	1,055.42	39.54	39.54	2.88	4,929.92	620.02
Taylor	92.16	163.25	2.80	2.80	0.09	693.08	8.42
Terrell	890.56	1,697.22	13.46	13.46	0.45	4,554.08	153.52
Terry	217.93	388.12	6.39	6.39	0.20	5,118.11	70.81
Throckmorton	221.50	393.95	6.55	6.55	0.20	1,242.06	15.21
Titus	42.19	74.68	1.29	1.29	0.04	506.68	8.03
Tom Green	170.07	304.64	4.76	4.76	0.14	1,945.37	23.40
Travis	3.37	5.97	0.10	0.10	0.00	14.43	0.07
Trinity	10.94	19.88	0.27	0.27	0.01	193.38	3.42
Tyler	463.76	896.18	5.69	5.69	0.25	57,953.39	1,201.05
Upshur	604.48	1,126.42	11.73	11.73	0.30	10,582.53	238.20
Upton	1,602.98	2,998.03	30.90	30.90	1.09	32,833.54	647.89
Uvalde	0.20	0.26	0.02	0.02	0.00	4.37	0.01
Val Verde	210.53	394.38	3.90	3.90	0.10	620.76	21.64
Van Zandt	193.81	352.82	4.81	4.81	0.15	1,204.59	23.27

Table 1-3. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Victoria	287.47	535.68	5.67	5.67	0.16	3,296.01	69.83
Walker	13.49	24.74	0.31	0.31	0.01	85.26	1.73
Waller	88.01	106.67	2.83	2.83	0.11	2,859.24	56.46
Ward	1,288.64	2,381.97	28.00	28.00	0.94	9,588.88	230.25
Washington	256.76	485.36	4.31	4.31	0.14	2,513.65	64.54
Webb	3,123.82	5,806.41	62.66	62.66	1.48	28,275.41	664.71
Wharton	692.11	1,309.84	11.43	11.43	0.37	15,986.48	354.54
Wheeler	2,223.92	4,231.74	34.40	34.40	1.15	40,674.02	955.94
Wichita	1,185.96	2,099.33	36.23	36.23	1.13	5,040.04	46.60
Wilbarger	174.53	308.95	5.33	5.33	0.17	1,147.90	13.03
Willacy	353.53	681.05	4.59	4.59	0.19	8,274.58	193.92
Williamson	9.07	16.05	0.28	0.28	0.01	53.29	0.33
Wilson	129.98	230.01	3.98	3.98	0.12	757.55	6.10
Winkler	917.14	1,698.44	19.52	19.52	0.63	7,815.47	141.18
Wise	2,749.59	5,099.17	55.75	55.75	1.35	24,225.59	597.53
Wood	239.16	438.82	5.52	5.52	0.18	4,200.35	82.03
Yoakum	1,074.18	1,960.14	26.21	26.21	0.88	25,649.46	414.59
Young	556.32	978.60	17.57	17.57	0.50	3,394.26	35.11
Zapata	4,438.24	8,472.07	65.54	65.54	2.24	13,384.86	594.31
Zavala	64.75	114.70	1.94	1.94	0.05	1,016.76	14.24
Total:	**128,330.85**	**218,196.11**	**2,570.01**	**2,570.01**	**81.34**	**1,568,522.73**	**34,090.45**

2.0 AVAILABLE EMISSIONS ESTIMATION METHODOLOGY REVIEW

One of the objectives of this project was to conduct a literature review of available studies, reports, and research activities relevant to the development of a 2008 base year area source emissions inventory for upstream oil and gas production sites. From this review, a preferred emission estimation approach for each category was selected. In the project Work Plan, this work was referred to as Task 2. The existing studies which were reviewed, and a summary of the available and recommended emission estimation approaches for each source type were presented in a memo submitted to TCEQ on April 26, 2010. This memo included summaries of the data required to implement the preferred approach, and ERG's recommendations how best to obtain the needed data. In addition, any data gaps identified that impacted the ability to develop a 2008 inventory estimate for each source type were described and possible methods for addressing the data gaps (through the use of existing or default data) were presented.

Appendix A contains a copy of this memo summarizing the activities conducted under this part of the project.

3.0 IDENTIFICATION OF OIL AND GAS OWNERS/OPERATORS AND SURVEY DEVELOPMENT

As mentioned above, one of the objectives of this project was the development of survey materials that may be used to obtain the detailed, source-specific data needed to estimate county-level emissions for each source type. Additionally, identification of the producers of oil and gas for each county was needed to assist in possible future implementation of a field survey to obtain the required data. In the project Work Plan, this work was referred to as Task 3. Both of these objectives were met and this information was provided to TCEQ in a memo submitted on July 9, 2010.

Appendix B contains a copy of this memo summarizing the activities conducted under this part of the project.

4.0 EMISSIONS CALCULATION METHODOLOGY

This section presents a discussion of each source type included in the 2008 baseline area source emissions inventory of upstream oil and gas production sites. Each source type is discussed separately, including a process description, a description of the emissions estimation methodology used to calculate emissions, a description of the derivation of all activity data and input parameters used in the calculation, presentation of all data used in the calculation, the equations used to calculate emissions for each source type, and an example calculation for each source type.

4.1 Compressor Engines

Natural gas fueled spark-ignited internal combustion engines are normally used to drive gas field compressors. The compressors are used to boost the pressure of well-head natural gas so that it can be injected into higher pressure gathering lines. These compressor engines burn well-head natural gas and can represent a significant NO_x area emissions source category as they generally operate 8,760 hours per year with minimum down-time.

Emissions from compressor engines were calculated using a methodology similar to that employed in the Houston Advanced Research Council's (HARC) study "Natural Gas Compressor Engine Survey and Engine NO_x Emissions at Gas Production Facilities" (HARC, 2005).[1] For this 2008 inventory, the calculation methodology uses annual natural gas production by county along with vender-derived county-level emission factors to determine emissions from compressor engines at gas production facilities. ERG combined engine data from the HARC study with two 2007 TCEQ engine surveys conducted on the counties located in the Dallas - Forth Worth (DFW) metropolitan area and Southeast Texas. The two TCEQ surveys were completed as efforts to amend the state clean air plan for ozone. Engine operators reported engine models and sizes, and other data to TCEQ. Using these data, ERG calculated county-level emissions from compressor engines with the following equation:

[1] The HARC 2005 report was updated in 2006 to include more engine size categories and to add the year 2000 to the previous inventory; however, these updates did not change the calculation methodology used in the original 2005 report.

$$E_{ik} = TGP_i \times \left(\frac{F_{1i} * F_{2j} * EF_{jk} * C_i}{907{,}180} \right)$$

where:

- E_{ik} is the emissions for county i, and pollutant k [tons/yr]
- TGP_i is the total gas production in county i [Mscf/yr]
- F_{1i} is the fraction of wells requiring compression in county i
- F_{2j} is the fraction of compression load represented by engines of type j
- EF_{jk} is the emission factor for engine type j, and pollutant k [g/Hp-hr]
- C_i is the compression requirements for county i [Hp-hr/Mscf]
- 907,180 is the conversion factor from grams to tons of emissions

Total gas production in county i, TGP_i:

Natural gas production data by county (TGP_i) was provided for 2008 by the TRC for 241 counties. Burnet, Castro, Collin, Comal, Dallam, Deaf Smith, Delta, El Paso, Gillespie, Hall, Kendall, Lamar, Llano, Mason, Parmer, Presidio, Randall, San Saba, and Swisher counties had no gas or oil production in 2008.

Fraction of wells requiring compression in county i, F_{1i}:

Upon initial well completion, not all wells require compression. Therefore, the fraction of wells requiring compression (F_{1i}) was estimated in the HARC study as the fraction of active wells greater than one year old. Using the same assumption for this 2008 inventory, ERG determined the fraction of wells active in 2008 that were greater than one year old using the following equation:

$$\text{Fraction of Wells} > 1 \text{ Year Old} = 1 - \left(\frac{\text{(Wells Completed in 2007)}}{\text{(Total Active Wells on February 5, 2008)}} \right)$$

For each Texas Railroad Commission (TRC) District, results are shown in Table 4-1. ERG determined the number of wells completed in 2007 using TRC annual drilling, completion, and plugging summaries which are available at: http://www.rrc.state.tx.us/data/drilling/drillingsummary/index.php. Total active wells by district for January 1, 2008 are not readily available from the TRC website; therefore, in order to determine total active wells, ERG used gas well distribution data showing the number of regular producing gas wells by county. Gas well distribution data by county is only available from the TRC website on a bi-annual (February and September) basis and can be found at:

http://www.rrc.state.tx.us/data/wells/wellcount/index.php. Using the February 2008 TRC report, ERG summed the county specific numbers for regular producing gas wells by TRC district.

The fraction of wells greater than one year old are likely to be slightly different than what is shown below because each well that was completed in 2007 could have been completed on any day of that year. Using the methodology explained above, ERG has assumed that all wells completed in 2007 were completed on February 5, 2007. ERG applied the fractions shown in the Table 4-1 to the counties in each respective district.

Table 4-1. Fraction of Wells >1 Year Old

TRC District	Wells Completed in 2007	Total Active Wells on February 5, 2008	Fraction of Wells >1 Year Old (F_{1i})
1	176	2,513	0.9300
2	515	3,293	0.8436
3	317	3,977	0.9203
4	1,070	13,098	0.9183
5	644	7,008	0.9081
6	1,957	13,706	0.8572
7B	121	6,769	0.9821
7C	947	13,101	0.9277
8	225	3,909	0.9424
8A	36	265	0.8642
9	1,781	7,739	0.7699
10	854	12,647	0.9325
Total	8,643	88,025	0.9018

Fraction of compression load represented by engines of type j, F_{2j}:

Fraction of compression load by engine type (F_{2j}) was determined by the HARC report for eight engine types (i.e. 2-cycle lean, 50-499 Hp; 4-cycle lean, 50-499 Hp; etc.) in three areas categorized by their attainment status, including the Texas attainment areas, the Houston nonattainment area, and the Dallas nonattainment area. For this 2008 inventory, in an effort to achieve more accurate emissions data results, ERG combined data from the two 2007 TCEQ engine surveys with the HARC survey data and determined the distribution or fraction of compression load by engine type for the most reported engines (comprising 80% of the population) for each of the three categories used in the HARC report.

In order to prevent duplication, 103 engines from the HARC study were removed prior to combining the data with the two 2007 TCEQ engine surveys. These engines were removed because they were located in thirteen counties (Austin, Ellis, Hardin, Houston, Jasper, Jefferson, Newton, Polk, San Augustine, San Jacinto, Trinity, Tyler, and Walker) that overlapped with the 2007 survey data. The 2007 data had a greater population (335) of engines for these counties than the HARC study. ERG also removed the following engines from the two 2007 TCEQ engine survey data sets:

- Fifty-five engines from the DFW survey and two engines from the Southeast survey that lacked engine characteristic data;
- Two engines from the HARC study that were labeled as electric motors;
- Three engines from the HARC study that were identified as not being located at a gas well; and
- One engine from the DFW survey identified as no longer operational.

After combining the data sets (and removing certain engines as discussed above), a total of 2,880 engines were included for the analysis as detailed in Table 4-2 below.

Table 4-2. Engine Count by Survey

Specific Survey	Number of Engines
HARC Survey	1,252
2007 TCEQ DFW Survey	1,321
2007 TCEQ SE Survey	307
Total	2,880

In order to ensure engines were grouped appropriately, ERG performed extensive internet research as well as phone interviews with engine manufactures to standardize engine make and model naming conventions. Additionally, some assumptions were made such as all Caterpillar engines reported in the survey data are natural gas fired (many respondents had reported engine models without using the term "G" in front of the model number which defines the engine as a natural gas fired engine). ERG also assumed that any potential (future) engines identified in the 2007 DFW survey would be located in the Dallas nonattainment area. Minor gap-filling was also performed on the combined dataset which included completing any empty "Engine Cycle (2 or 4)" data fields based on the known engine make and model.

Using the combined dataset, ERG determined an average size (horsepower) for each specific engine model and then calculated the fraction of compression load by engine type (F_{2j})

for three categories (Texas attainment areas, the Dallas nonattainment area, and the Houston nonattainment area) as shown in Tables 4-3 through 4-5. Due to minimal engine data in the Jefferson, Hardin, and Orange nonattainment counties, these counties were combined into the Houston nonattainment area.

<u>Emission factor for engine type j, and pollutant k, EF_{jk}:</u>

Emission factors for each unique engine make and model (based on approximately the top 80% most reported engines in each of the three attainment status categories) are shown in Tables 4-3 through 4-5. The NO_x, CO, and VOC emission factors for the engines located in attainment counties (Table 4-3) were each determined through extensive internet research as well as phone interviews with specific engine manufactures. Manufacture emissions data was averaged across all performance data given for a specific engine.

NO_x emission factors for the engines located in nonattainment counties (Tables 4-4 and 4-5) are based on Texas's rules for Houston-Galveston-Brazoria and Dallas-Fort Worth eight-hour ozone nonattainment areas (30 TAC, Chapter 117, Subchapter D, Division 1 and 2). These rules regulate certain minor sources of NO_x, including some stationary, gas-fired reciprocating internal combustion engines. Considering the Houston-Galveston-Brazoria rule, all stationary, gas-fired reciprocating internal combustion engines greater than 50 horsepower are restricted to 0.5 g/Hp-hr. Considering the Dallas-Fort Worth rule, rich burn engines greater than 50 horsepower are restricted to 0.5 g/Hp-hr, lean burn engines installed or moved before June 1, 2007 are limited to 0.7 g/Hp-hr, and lean burn engines installed or moved after June 1, 2007 are limited to 0.5 g/Hp-hr. Assuming no engines were installed on wells younger than 1 year old, and using the number of new oil wells completed for 2006 in DFW nonattainment counties (data which can be obtained from the TRC), ERG calculated that ~16% percent of lean burn engines operating in DFW counties in 2008 could have potentially been installed after June 1, 2007. Therefore, an adjusted NO_x emission factor of 0.67 g/Hp-hr [(0.50 * .16) + (0.70 * .84)] was applied to any lean burn engines in Table 4-4.

CO and VOC emission factors for the engines located in nonattainment counties (Tables 4-4 and 4-5) were determined through extensive internet research as well as phone interviews with specific engine manufactures. However, ERG assumed any four stroke rich burn engine, greater than 50 Hp and located in a nonattainment area, would have non-selective catalytic

Table 4-3. Emission Factor Data for Texas Attainment Areas

Engine Make & Model	SCC	Number of Engines [Lean / Rich]	Engine Horsepower (Hp)	Compression Load by Engine Type (F_{2j})	Fuel Consumption (MMBtu/Hp-hr)	Emission Factor (EF_{jk}) (g/Hp-hr)				
						PM	NOx	CO	VOC	SO_2
CAT G3306 NA	2310021302	0 / 165	145	8.98%	0.007775	3.35E-02	13.48	13.46	0.22	2.07E-03
CAT G3304 NA	2310021302	0 / 130	95	4.64%	0.007567	3.26E-02	21.08	1.6	0.24	2.02E-03
Wauk VRG330	2310021302	0 / 107	68	2.73%	0.008038	3.46E-02	12.951	1.104	0.05 (1)	2.14E-03
CAT G3306 TA	2310021302	0 / 67	203	5.11%	0.008098	3.49E-02	16.57	16.57	0.12	2.16E-03
Wauk F817 G	2310021302	0 / 42	87	1.37%	0.007253	3.13E-02	16.0	1.0	1.7 (2)	1.93E-03
AJAX DPC-60	2310021102	39 / 0	58	0.85%	0.009000	1.57E-01	4.4	1.7	0.8	2.40E-03
AJAX DPC-115	2310021102 /2310020600	31 / 2	110	1.36%	0.009000	1.57E-01	4.4	2.4	0.9	2.40E-03
Wauk F1197 G	2310021302	0 / 32	183	2.20%	0.007253	3.13E-02	20.0	1.0	0.20 (1)	1.93E-03
CAT G3406 NA (3)	2310021302	0 / 31	290	3.37%	0.007407	3.19E-02	23.2267	6.14	0.17	1.98E-03
CAT G3516 TALE	2310021203	30 / 0	1245	14.02%	0.007365	2.58E-04	2.0	1.805	0.28	1.96E-03
CAT G3306 NA HCR (4)	2310021302	0 / 29	145	1.58%	0.007775	3.35E-02	13.48	13.46	0.22	2.07E-03
AJAX DPC-360	2310021102 /2310020600	27 / 1	346	3.64%	0.008400	1.46E-01	6.3	1.4	1.0	2.24E-03
AJAX DPC-180	2310021102	28 / 0	173	1.82%	0.008400	1.46E-01	6.3	1.4	1.0	2.24E-03
AJAX DPC-140	2310021102	26 / 0	134	1.31%	0.008200	1.43E-01	10.5	1.3	0.7	2.19E-03
AJAX DPC-280	2310021102	25 / 0	269	2.52%	0.008200	1.43E-01	11.4	1.3	0.7	2.19E-03
Wauk VRG220 (5)	2310021301	0 / 24	45	0.41%	0.008038	3.46E-02	12.951	1.104	0.05 (1)	2.14E-03
AJAX DPC-80	2310021102	22 / 0	77	0.64%	0.008900	1.55E-01	4.4	2.8	0.9	2.37E-03
CAT G342 NA (6)	2310021302	0 / 21	225	1.77%	0.008588	3.70E-02	0.101	0.317	0.086 (1)	2.29E-03
AJAX C-42	2310021101 /2310020600	19 / 1	40	0.30%	0.009900	1.72E-01	4.4	3.3	0.8	2.64E-03
GEMINI G26	2310021301	0 / 19	26	0.19%	0.008038	3.46E-02	12.951	1.104	0.05 (1)	2.14E-03
Wauk L7042 GL (7)	2310021203	19 / 0	1357	9.68%	0.007238	2.53E-02	1.0	2.85	0.95 (1)	1.93E-03
CAT G342 TA (6)	2310021302	0 / 16	225	1.35%	0.008588	3.70E-02	0.101	0.317	0.086 (1)	2.29E-03
Wauk VRG310 (5)	2310021302	0 / 16	68	0.41%	0.008038	3.46E-02	12.951	1.104	0.05 (1)	2.14E-03
CAT G399 TA (10)	2310021403	0 / 16	802	4.82%	0.008710	3.75E-02	0.7756	0.1592	0.0086 (8)	2.32E-03
Wauk L7042 GSI (10)	2310021403	0 / 15	1357	7.64%	0.007558	3.26E-02	1.6	1.3	0.025 (1)	2.02E-03
CAT G398 TA (9, 10)	2310021403	0 / 15	605	3.41%	0.008710	3.75E-02	0.7756	0.1592	0.0086 (8)	2.32E-03
CAT G3406 TA	2310021302	0 / 14	290	1.52%	0.007407	3.19E-02	23.2267	6.14	0.17	1.98E-03
CAT G3512 TALE	2310021203	14 / 0	932	4.90%	0.007385	2.58E-04	2.0	2.04	0.295	1.97E-03
CAT G3406 (11)	2310021302	0 / 14	290	1.52%	0.007407	3.19E-02	23.2267	6.14	0.17	1.98E-03
Wauk L7042 G (10)	2310021403	0 / 14	961	5.05%	0.007180	3.09E-02	1.6	1.3	0.025 (1)	1.91E-03

Table 4-3. Emission Factor Data for Texas Attainment Areas (Cont.)

Engine Make & Model	SCC	Number of Engines [Lean / Rich]	Engine Horsepower (Hp)	Compression Load by Engine Type (F_{2j})	Fuel Consumption (MMBtu/Hp-hr)	Emission Factor (EF_{jk}) (g/Hp-hr)				
						PM	NOx	CO	VOC	SO_2
AJAX DPC-230	2310021102 /2310020600	10 / 1	221	0.91%	0.008700	1.52E-01	4.4	2.4	0.90	2.32E-03
TOTAL	**--**	**1082**	**--**	**100%**	**Weighted Average EFs**	**0.04**	**7.57**	**3.85**	**0.35**	**2.07E-03**

1. Non-Methane Hydrocarbon.
2. Total Hydrocarbon.
3. There is no emission factor data available distinguishing CAT G4306 NA from G3406 TA, thus it was assumed that emission factors were the same for both models.
4. There is no emission factor data available distinguishing CAT G3306 NA HCR from G3306 NA, thus it was assumed that emission factors were the same for both models.
5. Based on discussions with Waukesha, the VRG220 and VRG310 models have the same emission factors as the VRG330.
6. Emissions data based on AP-42 background document with no HAP control. Emission factor data did not differentiate between a G342 TA or NA engine, thus same emission factors were assumed for both models.
7. No emission factor data could be found for this engine. Because it is a 4-stroke and has similar horsepower to the Wauk VRG220, it was assumed that emission factors were the same for both models.
8. Assumed to be equal to CAT G342 NA.
9. No emission factor data could be found for this engine. Since it is a similar model manufactured in the same time period, it was assumed that emission factors were the same as CAT G399 TA.
10. Engines are documented as having non-selective catalytic reduction (NSCR) control technology. ERG has applied a 90% reduction to the emission factors for CO and VOC for these engines
11. There is some ambiguity in the survey data as to whether this engine is a CAT G3406 NA or TA; however, the emissions are the same for the G3406 TA and NA versions.

Table 4-4. Emission Factor Data for Dallas Nonattainment Areas

Engine Make & Model	SCC	Number of Engines [Lean / Rich]	Engine Horsepower (Hp)	Fraction of Compression Load by Engine Type (F_{2j})	Fuel Consumption (MMBtu/Hp-hr)	Emission Factor (EF_{jk}) (g/Hp-hr)				
						PM	NO_x	CO	VOC	SO_2
CAT G3306 NA	2310021402	0 / 281	145	6.10%	0.007775	3.35E-02	0.50	1.346	0.022	2.07E-03
CAT G3304 NA HCR (2)	2310021402	0 / 72	95	1.02%	0.007567	3.26E-02	0.50	0.16	0.024	2.02E-03
Cummins G8.3	2310021402	0 / 64	112	1.07%	0.008228	3.55E-02	0.50	0.946	0.001 (3)	2.19E-03
CAT G3516 TALE	2310021203	60 / 0	1245	11.18%	0.007364	2.58E-04	0.67	1.805	0.28	1.96E-03
CAT G3606 TALE LCR (4)	2310021203	59 / 0	1835	16.21%	0.006612	2.31E-04	0.67	2.5625	0.605	1.76E-03
CAT G3306 NA HCR (5)	2310021402	0 / 58	145	1.26%	0.007775	3.35E-02	0.50	1.346	0.022	2.07E-03
Wauk L7044 GSI	2310021403	0 / 50	1540	11.53%	0.007665	3.30E-02	0.50	1.03	0.02 (6)	2.04E-03
Wauk L5794 GSI	2310021403	0 / 49	1265	9.28%	0.007430	3.20E-02	0.50	0.88	0.03 (3)	1.98E-03
CAT G3304 NA	2310021402	0 / 46	95	0.65%	0.007567	3.26E-02	0.50	0.16	0.024	2.02E-03
Wauk L7042 GSI	2310021403	37 / 0	1357	7.52%	0.007557	2.64E-04	0.67	13.0	0.25 (3)	2.02E-03
CAT G3516	2310021203	0 / 29	1050	4.56%	0.007700	3.32E-02	0.50	1.31	0.029 (3)	2.05E-03
CAT G3516 TALE AFRC (7)	2310021203	29 / 0	1245	5.41%	0.007364	2.58E-04	0.67	1.805	0.28	1.96E-03
Cummins 8.3 GTA	2310021402	0 / 28	183	0.77%	0.007380	3.18E-02	0.50	0.205	0.007 (3)	1.97E-03
CAT G3608 TALE	2310021203	28 / 0	2408	10.09%	0.006592	2.31E-04	0.67	2.56	0.5975	1.76E-03
CAT G3606 TALE	2310021203	26 / 0	1835	7.14%	0.006612	2.31E-04	0.67	2.56	0.605	1.76E-03
Cummins G5.9	2310021402	0 / 25	84	0.31%	0.007914	3.41E-02	0.50	1.451	0.022 (3)	2.11E-03
AJAX DPC-180	2310021102/ 2310020600	7 / 17	173	0.62%	0.008400	1.46E-01	0.55	1.4	1.0	2.24E-03
CAT G3306 TA	2310021402	0 / 19	203	0.58%	0.008098	3.49E-02	0.50	1.657	0.012	2.16E-03
CAT G3508 TALE	2310021203	17 / 0	670	1.71%	0.007510	2.63E-04	0.67	1.84	0.3	2.00E-03
CAT G3512 TALE	2310021203	17 / 0	932	2.37%	0.007385	2.58E-04	0.67	2.04	0.295	1.97E-03
AJAX DPC-140	2310021102/ 2310020600	3 / 11	134	0.28%	0.008200	1.43E-01	0.54	1.3	0.7	2.19E-03
AJAX DPC-115	2310021102/ 2310020600	5 / 8	110	0.21%	0.009000	1.57E-01	0.57	2.4	0.9	2.40E-03
Wauk VRG330	2310021402	0 / 12	68	0.12%	0.008038	3.46E-02	0.50	0.110	0.005 (3)	2.14E-03
TOTAL	**--**	**1048**	**--**	**100%**	**Weighted Average EFs**	**0.02**	**0.61**	**2.62**	**0.30**	**1.93E-03**

1. NOx emission factors were adjusted for 30 TAC, Chapter 117, Subchapter D, Division 2 nonattainment rule. Also, ERG assumed any four stroke rich burn engine, greater than 50 Hp and located in a nonattainment area, would have non-selective catalytic reduction (NSCR) control technology. ERG has applied a 90% reduction to the emission factors for CO and VOC for these engines.
2. There is no emission factor data available distinguishing CAT G3304 NA HCR from G3304 NA, thus it was assumed that emission factors were the same for both models.
3. Non-Methane Hydrocarbon.
4. There is no emission factor data available distinguishing CAT G3606 TALE LCR from G3606 TALE, thus it was assumed that emission factors were the same for both models. Furthermore, although data received from the 2007 DFW survey reported the CAT G3606 TALE LCR model has a rich burn engine; based on further research, ERG determined that this engine is a lean burn engine.
5. There is no emission factor data available distinguishing CAT G3306 NA HCR from G3306 NA, thus it was assumed that emission factors were the same for both models.
6. Value is estimated because no data is available.
7. There is no emission factor data available for this model engine with an air fuel ratio control, thus emission factors were assumed to be the same as the CAT G3516 TALE. Furthermore, several of these engines were reported as rich burn in the data received from the 2007 DFW survey; however, based on further research, ERG determined that this engine can only be a lean burn engine.

Table 4-5. Emission Factor Data for Houston Nonattainment Areas

Engine Make & Model	SCC	Number of Engines [Lean / Rich]	Engine Horsepower (Hp)	Fraction of Compression Load by Engine Type (F_{2j})	Fuel Consumption (MMBtu/Hp-hr)	Emission Factor (EF_{jk}) (g/Hp-hr)				
						PM	NO_x	CO	VOC	SO_2
CAT G3304 NA	2310021402	0 / 26	95	5.49%	0.007567	3.26E-02	0.50	0.16	0.024	2.02E-03
CAT G3306 NA	2310021402	0 / 24	145	7.73%	0.007775	3.35E-02	0.50	1.346	0.022	2.07E-03
Wauk VRG330	2310021402	0 / 23	68	3.47%	0.008038	3.46E-02	0.50	0.1104	0.005 (2)	2.14E-03
CAT G379 NA (3)	2310021402	0 / 14	327	10.17%	0.008710	3.75E-02	0.50	0.1592	0.009 (4)	2.32E-03
Wauk F1197 G	2310021402	0 / 13	183	5.28%	0.007253	3.13E-02	0.50	0.1	0.020 (2)	1.93E-03
CAT G3306 TA	2310021402	0 / 13	203	5.86%	0.008098	3.49E-02	0.50	1.657	0.012	2.16E-03
CAT G342 NA (5)	2310021402	0 / 10	225	5.00%	0.008588	3.70E-02	0.101	0.0317	0.009 (2)	2.29E-03
CAT G3406 TA	2310021402	0 / 9	290	5.80%	0.007407	3.19E-02	0.50	0.614	0.017	1.98E-03
Wauk F817 G	2310021402	0 / 7	87	1.35%	0.007253	3.13E-02	0.50	0.1	0.17 (6)	1.93E-03
AJAX C-42	2310021101	5 / 0	40	0.44%	0.009900	1.72E-01	4.4 (8)	3.3	0.8	2.64E-03
CAT G398 TA (3)	2310021403	0 / 5	605	6.72%	0.008710	3.75E-02	0.50	0.1592	0.009 (4)	2.32E-03
AJAX DPC-140	2310021102	5 / 0	134	1.49%	0.008200	1.43E-01	0.50	1.3	0.7	2.19E-03
SUPERIOR 8GTLB	2310021203	4 / 0	1100	9.77%	0.008788	3.07E-04	0.50	3.6	0.4	2.34E-03
CAT G379 TA (3)	2310021402	0 / 4	417	3.70%	0.008710	3.75E-02	0.50	0.1592	0.009 (4)	2.32E-03
CAT G3516 TALE	2310021203	3 / 0	1245	8.30%	0.007364	2.58E-04	0.50	1.805	0.28	1.96E-03
Wauk F11 G	2310021402	0 / 3	119	0.79%	0.007600	3.27E-02	0.50	0.079	0.027 (2)	2.03E-03
CAT G3306	2310021402	0 / 3	183	1.22%	0.007579	3.27E-02	0.50	0.146	0.012	2.02E-03
Wauk VRG220 (7)	2310021301	0 / 3	45	0.30%	0.008038	3.46E-02	12.951 (8)	1.104	0.05 (2)	2.14E-03
Wauk VRG330 TA	2310021402	0 / 3	100	0.67%	0.007307	3.15E-02	0.50	0.1587	0.002 (2)	1.95E-03
Wauk L7042 GL	2310021203	3 / 0	1357	9.04%	0.007237	2.53E-04	0.50	2.85	0.95 (2)	1.93E-03
Wauk L7042 G	2310021403	0 / 3	961	6.40%	0.007180	3.09E-02	0.50	1.3	0.025 (2)	1.91E-03
CAT G342 TA (5)	2310021402	0 / 2	225	1.00%	0.008588	3.70E-02	0.101	0.0317	0.009 (2)	2.29E-03
TOTAL		**199**		**100%**	**Weighted Average EFs**	**0.03**	**0.53**	**1.17**	**0.17**	**2.12E-03**

1. NOx emission factors were adjusted for 30 TAC, Chapter 117, Subchapter D, Division 2 nonattainment rule. Also, ERG assumed any four stroke rich burn engine, greater than 50 Hp and located in a nonattainment area, would have non-selective catalytic reduction (NSCR) control technology. ERG has applied a 90% reduction to the emission factors for CO and VOC for these engines.
2. Non-Methane Hydrocarbon.
3. No emission factors could be found for these engines. Since they are similar models manufactured in the same time period, it was assumed that emission factors were the same as CAT G399 TA.
4. Assumed to be equal to CAT G342 NA.
5. Emission factors are based on AP-42 background document testing with no HAP emission control. Emissions data did not differentiate between a G342 TA or NA engine, so it was assumed that they have the same emission factors. No control device is needed since NOx emissions are below Texas mandated emission standards.
6. Total Hydrocarbon.
7. Based on discussions with Waukesha, the VRG220 and VRG310 models have the same emission factors as the VRG330.
8. The AJAX C-42 and Wauk VRG220 engines are less than 50 Hp and therefore are not subject to 30 TAC, Chapter 117, Subchapter D, Division 2.

reduction (NSCR) control technology. AP-42 Section 3.2 (US EPA, 2000) recommends applying an efficiency of 90% to the uncontrolled emissions of CO for engines equipped with NSCR technology; other studies (EPRI 2005) state the technology can also achieve 85 to 90% reduction of VOCs. Therefore, the CO and VOC emission factors in Tables 4-4 and 4-5 reflect a 90% control efficiency adjustment.

All PM and SO_2 emission factors were obtained from AP-42 Section 3.2 (US EPA, 2000). PM emission factors are based on whether each engine is a 2 or 4 stroke lean-burn engine or a 4 stroke rich-burn engine. The PM emission factor represents both PM_{10} and $PM_{2.5}$. The SO_2 emission factor assumes the sulfur content in natural gas is 0.002 grams per standard cubic foot.

By applying the emissions data (EF_{jk}) in Tables 4-3 through 4-5 to the fraction of compression load by engine type (F_{2j}), a single set of weighted emission factors was calculated for each pollutant in each attainment status category.

<u>Compression requirements for county i, C_i</u>:

A compressor's operating behavior is generally dependent on the relationship between pressure ratio and volume or mass flow rate. In particular, the operating behavior for a compressor engine located at a gas well is based on the compressor suction and discharge pressures required to convey the natural gas from the well head to the gathering lines. These pressures, or the compression ratio, along with the natural gas flow-rate through the compressor, define the engine load in terms of the amount of mechanical work that is required to compress the natural gas produced by the well. This mechanical work, in terms of horsepower-hour (Hp-hr), is directly proportional to the volume of fuel, in terms of thousand cubic feet (Mscf), that must be burned by the compressor engine and the relationship is termed a *compression requirement* (Hp-hr/Mscf). Special compressor calculators can be used to convert inlet and outlet pressures into *compression requirements* which can then be used to determine emissions created by compressor engines. Because of this direct relationship of mechanical work to volume of fuel burned, one would expect a 100 Hp engine to burn almost an equal amount of fuel as two (2) 50 Hp engines when compressing the same volume of natural gas produced by the same well. Therefore, it is not necessary to know the specific numbers of engines, or their individual sizes when calculating emissions from compressors at the county level.

The 2005 HARC report developed compression requirements ranging between 3.1 and 3.5 (Hp-hr/Mscf) for three distinct districts in eastern Texas, including one attainment area and two nonattainment areas (Houston and Dallas) by obtaining typical well pressures and gathering line pressures through a field study. The engines in this particular field survey were operated at loads ranging from about 10% to 70% of full load, and averaged 40% load. Additionally, compression requirements deduced from two Pollution Solutions studies are relatively in-line with the compression requirements used in the 2005 HARC report. More specifically, a 191 Hp-day/Mscf compression requirement determined in a 2005 Pollutions Solutions study, when adjusted[2] for the findings in a 2008 Pollution Solutions study, yields a *compression requirement* of 2.97 (Hp-hr/Mscf).

Compression requirements calculated by specific Texas studies are shown in Table 4-6. Those compression requirements were applied to counties in each respective TRC District and an average was calculated for application to the rest of Texas.

Table 4-6. Average Compression Requirements (Hp-hr/Mscf)

Study	TRC District 2	TRC District 3	TRC District 6	All Other Texas Areas
HARC 2005	3.5	3.1	3.1	--
2005 and 2008 Pollution Solutions (1)	--	--	2.97	--
Final	**3.5**	**3.1**	**3.03**	**3.21** (2)

1. Included Gregg, Harrison, Rusk, Smith, Upshur, and Panola Counties.
2. TRC districts 2, 3, and 6 averaged together.

[2] In a 2002 emissions inventory (Pollution Solutions, 2005) entitled "Tyler/Longview/Marshall Flexible Attainment Region Emission Inventory", the author developed a *compression requirement* (Hp-day/MSCF) through survey data assuming the compressor engines were operating under full load or maximum installed horsepower. This assumption caused an overestimation of the amount of fuel that was consumed by the compressor engines and consequently overestimated the amount of emissions from these engines. A more recent study by Pollution Solutions (2008) entitled "2005 and 2007 Compressor Engine Emissions and Load Factors Report" determined average load factors for three engine categories, all of which were less than 100%. For engines less than 240 Hp, the load factor was 70%. For engines between 240-500 Hp, the load factor was 69%. For engines greater than 500 Hp, the load factor was 58%. Applying the load factors reduced the estimated 2005 emissions of NO_x by 34% and similar reductions were seen for VOC and CO.

HAP Emissions for Compressor Engines

HAP emissions from compressor engines were calculated using VOC and PM speciation data as follows:

$$E_{VOC\text{-}HAP} = E_{VOC} \text{ x } (E_{\%VOC\text{-}HAP} /100)$$

where:

$E_{VOC\text{-}HAP}$ = Speciated VOC-HAP emissions [tons/yr]
E_{VOC} = VOC emissions [tons/yr]
$E_{\%VOC\text{-}HAP}$ = % HAP composition of VOC emissions

and

$$E_{PM\text{-}HAP} = E_{PM} \text{ x } (E_{\%PM\text{-}HAP} /100)$$

where:

$E_{PM\text{-}HAP}$ = Speciated PM-HAP emissions [tons/yr]
E_{PM} = PM emissions [tons/yr]
$E_{\%PM\text{-}HAP}$ = % HAP composition of PM emissions

Appendix C contains the VOC and PM HAP speciation data.

Emissions for county i, and pollutant k, EF_{ik}:

Appendix D presents county-level emissions for compressor engines corresponding to county-level natural gas production, based on the input variables discussed above. Tables 4-7 through 4-9 depict the distribution of emissions for various engine types by Source Classification Code (SCC) as found in the Texas attainment areas, the Houston nonattainment area, and the Dallas nonattainment area. ERG applied these distributions in order to determine compressor engine emissions by SCC and county (see Appendix D). Table 4-10 defines each SCC used for Compressor Engines.

Table 4-7. Distribution of Compressor Engine Emissions by SCC for Texas Attainment Counties

SCC	PM	NO_x	CO	VOC	SO_2
2310020600	1.10%	0.16%	0.11%	0.75%	0.34%
2310021101	1.15%	0.13%	0.17%	0.59%	0.36%
2310021102	44.40%	9.21%	3.80%	29.00%	13.93%
2310021103	0%	0%	0%	0%	0%
2310021201	0%	0%	0%	0%	0%
2310021202	0%	0%	0%	0%	0%
2310021203	7.23%	4.76%	11.53%	37.84%	26.92%
2310021301	0.48%	0.77%	0.12%	0.08%	0.61%
2310021302	28.83%	58.22%	51.62%	21.66%	36.53%
2310021303	0%	0%	0%	0%	0%
2310021401	0%	0%	0%	0%	0%
2310021402	0%	0%	0%	0%	0%
2310021403	16.81%	26.75%	32.64%	10.08%	21.30%

Table 4-8. Distribution of Compressor Engine Emissions by SCC for Dallas Nonattainment Counties

SCC	PM	NO_x	CO	VOC	SO_2
2310020600	5.93%	0.72%	0.46%	2.39%	0.92%
2310021101	0%	0%	0%	0%	0%
2310021102	2.42%	0.29%	0.20%	0.99%	0.38%
2310021103	0%	0%	0%	0%	0%
2310021201	0%	0%	0%	0%	0%
2310021202	0%	0%	0%	0%	0%
2310021203	24.14%	63.66%	49.49%	87.85%	56.38%
2310021301	0%	0%	0%	0%	0%
2310021302	0%	0%	0%	0%	0%
2310021303	0%	0%	0%	0%	0%
2310021401	0%	0%	0%	0%	0%
2310021402	20.38%	9.82%	4.88%	0.75%	12.77%
2310021403	47.13%	25.51%	44.97%	8.02%	29.55%

Table 4-9. Distribution of Compressor Engine Emissions by SCC for Houston Nonattainment Counties

SCC	PM	NO_x	CO	VOC	SO_2
2310020600	0%	0%	0%	0%	0%
2310021101	2.79%	3.68%	1.25%	2.03%	0.55%
2310021102	7.76%	1.40%	1.65%	5.96%	1.54%
2310021103	0%	0%	0%	0%	0%
2310021201	0%	0%	0%	0%	0%
2310021202	0%	0%	0%	0%	0%
2310021203	0.27%	25.54%	64.67%	84.77%	26.66%
2310021301	0.38%	7.32%	0.28%	0.09%	0.30%
2310021302	0%	0%	0%	0%	0%
2310021303	0%	0%	0%	0%	0%
2310021401	0%	0%	0%	0%	0%
2310021402	72.39%	49.69%	24.15%	5.90%	57.84%
2310021403	16.41%	12.36%	8.00%	1.25%	13.11%

Table 4-10. Compressor Engine SCC Definitions

SCC	Definition
2310020600	GENERIC NATURAL GAS FIRED COMPRESSOR ENGINES (All 2-CYCLE RICH BURN)
2310021101	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines <50 Hp
2310021102	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines 50 To 499 Hp
2310021103	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines 500+ Hp
2310021201	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines <50 Hp
2310021202	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines 50-499 Hp
2310021203	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines 500+ Hp
2310021301	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines <50 Hp
2310021302	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50 To 499 Hp
2310021303	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 500+ Hp
2310021401	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines <50 Hp W/ Nscr
2310021402	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50-499 Hp W/ Nscr
2310021403	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 500+ Hp W/ Nscr

Example Calculation for Compressor Engines

Using the equation provided above, ERG calculated NO_x emissions in Anderson County from natural gas fired 2-cycle lean burn compressor engines less than 50 Hp as follows:

$$E_{ik} = TGP_i \times \left(\frac{F_{1i} * F_{2j} * EF_{jk} * C_i}{907{,}180} \right)$$

where:

E_{ik} = NO_x emissions in Anderson County [tons/year]
TGP_i = 12,044,998 (the total gas production in Anderson County) [Mscf/yr]
F_{1i} = 0.8572 (the fraction of wells requiring compression in Anderson County)
F_{2j} = 0.0013 (the fraction of compression load represented by natural gas fired 2-cycle lean burn compressor engines)

EF_{jk} = 7.57 (the NO_x emission factor for natural gas fired 2-cycle lean burn compressor engines) [g/Hp-hr]
C_i = 3.03 (the compression requirements for Anderson County) [Hp-hr/Mscf]
907,180 is the conversion factor from grams to tons of emissions

Therefore:
E_{ik} = 12,044,998 [Mscf] x ((0.8572 * 0.0013 * 7.57 [g NO_x/Hp-hr] * 3.03 [Hp-hr/Mscf])/907,180)
E_{ik} = 0.339373 [tons NO_x/yr]

4.2 Artificial Lift (Pumpjack) Engines

A pumpjack is used to mechanically lift liquid out of the well if there is not enough bottom hole pressure for the liquid to flow all the way to the surface. The pumpjack tends to be driven by an electric motor; however, in isolated locations without access to electricity, combustion engines are used. The most common "off-grid" pumpjack engines run on casing gas produced from the well, but pumpjacks have been run on many types of fuel, such as propane (LPG) and diesel. Generally, pumpjacks have smaller engines than wellhead compressor engines.

Emissions from pumpjack engines were calculated using a methodology similar to that employed in a 2008 CENRAP study entitled: "Recommendations for Improvements to the CENRAP States' Oil and Gas Emission Inventories" (Bar-Ilan, et al., 2008). For this 2008 inventory, ERG calculated county-level emissions from pumpjack engines with the following equation:

$$E_{ik} = W_i \times f_{pumpjack} \times (1 - e_{pumpjack}) \times \left(\frac{EF_k * HP * LF * t_{annual}}{907{,}180} \right)$$

where:
E_{ik} is the emissions for county i, and pollutant k [tons/yr]
W_i is the total number of active oil wells in county i [wells]
$f_{pumpjack}$ is the fraction of oil wells with artificial lift engines
$e_{pumpjack}$ is the fraction of artificial lift engines that are electrically operated
EF_k is the emission factor for pollutant k [g/Hp-hr]
HP is the horsepower of the engine [Hp]
LF is the load factor of the engine while operating
t_{annual} is the annual number of hours the engine is used [hr/yr]
907,180 is the conversion factor from grams to tons of emissions

Total number of active oil wells in county i, W_i:

Total active oil wells by county for the full 2008 year are not readily available from the TRC website. However, oil well distribution data by county is available from the TRC website on a bi-annual (February and September) basis and can be found at: http://www.rrc.state.tx.us/data/wells/wellcount/index.php. ERG used the September 2008 TRC report to get a count of regular producing oil wells by county.

Fraction of oil wells with artificial lift engines, $f_{pumpjack}$:

The fraction of oil wells requiring artificial lift was estimated as the fraction of active oil wells greater than one year old. Typically, oil wells in their first year of existence do not require an artificial lift engine because the wells have enough bottom hole pressure for the oil to flow freely all the way to the surface. This trend was confirmed through phone interviews with five companies specializing in artificial lift engines (four engineering consultants with expertise in oil and gas production, and one company that sells, installs, and repairs pumpjacks and pumpjack engines). It was the general consensus among the interviewees that the majority of oil wells located in Texas are older than one year and thus would require some sort of artificial lift engine.

ERG determined the fraction of oil wells active in 2008 that were greater than one year old using the following equation:

$$\text{Fraction of Oil Wells} > 1 \text{ Year Old } = 1 - \left(\frac{(\text{Oil Wells Completed in 2007})}{(\text{Total Active Oil Wells on February 5, 2008})} \right)$$

ERG determined the number of oil wells completed in 2007 using TRC annual drilling, completion, and plugging summaries which are available at: http://www.rrc.state.tx.us/data/drilling/drillingsummary/index.php. ERG used oil well distribution data showing the number of regular producing oil wells by county. Oil well distribution data by county is only available from the TRC website on a bi-annual (February and September) basis and can be found at: http://www.rrc.state.tx.us/data/wells/wellcount/index.php. Using the February 2008 TRC report, ERG summed the county specific numbers for regular producing oil wells.

The fraction of oil wells greater than one year old was determined to be 0.967 (1 – (5,084 / 153,831) = 0.967). The actual fraction may be slightly different because each oil well that was completed in 2007 could have been completed on any day of that year. However, using the methodology explained above, ERG has assumed that all wells completed in 2007 were completed on February 5, 2007.

Fraction of artificial lift engines that are electrically operated, $e_{pumpjack}$:

ERG assumed that 70% of the artificial lift systems located in Texas operate with an electric motor as opposed to a fuel driven engine. This assumption was based on phone interviews with four companies specializing in artificial lift engines, three of which were engineering consultants with expertise in oil and gas production, and one company that sells, installs, and repairs pumpjacks and pumpjack engines. From these interviews, it was ascertained that it is most common to run pumpjack engines on electricity as this is the most cost effective option, thus if an oil well has access to electricity, electricity would typically be used to power the artificial lift engine. Fractions of artificial lift engines that are electrically operated ranged from 50 to 90 percent among interviewees. Therefore, ERG used a conservative estimate of 70%.

Emission factor for pollutant k, EF_k:

Through various phone interviews, ERG determined that the most popular pumpjack engines located in Texas are those in the Arrow C series. These engines burn natural gas and range from about 5 to 32 horsepower (depending on the model number). Criteria pollutant emission factors for the Arrow C engine models were provided by the manufacturer and are shown in Table 4-11. A single set of averaged emission factors was calculated for each pollutant assuming equal fuel usage by each engine size for all pollutants.

The New Source Performance Standard (NSPS), Subpart JJJJ limits emissions of NO_x, CO, and VOC from stationary spark ignition internal combustion engines less than 500 horsepower that were manufactured after July 1, 2008. Also, stationary spark ignition engines that were modified or reconstructed after June 12, 2006 are subject to the rule. As a conservative estimate, ERG assumed all pumpjack engines were manufactured prior to July 1, 2008 and/or were not modified or reconstructed after June 12, 2006. Therefore, no pumpjack engines in this analysis are considered subject to the emission limitations of NSPS, Subpart JJJJ.

All PM and SO_2 emission factors were obtained from AP-42 Section 3.2 (US EPA, 2000). The PM emission factor is 9.50E-03 lb/MMBtu (based on a 4 stroke rich-burn engine). The PM emission factor represents both PM_{10} and $PM_{2.5}$. The SO_2 emission factor is 5.88E-04 lb/MMBtu and assumes the sulfur content in natural gas is 0.002 grams per standard cubic foot. Both of these emission factors have been converted to g/Hp-hr using the fuel consumption rate of the engine.

Table 4-11. Common Pumpjack Engine Emission Factors

Arrow C Series Model	Horsepower (Hp)	Fuel Consumption (MMBtu/Hp-hr)	Emission Factor for Engine Type j, and Pollutant k (g/Hp-hr) (EF_{jk})				
			PM	NO_x	CO	VOC	SO_2
C-46	11	0.0126	0.054	9.26	20.19	0.006	3.36E-03
C-66	15.8	0.0117	0.050	14.54	4.03	0.332	3.12E-03
C-96	21.4	0.0121	0.052	11.87	5.05	0.142	3.23E-03
C-106	34	0.0092	0.040	23.32	0.222	0.094	2.46E-03
Average	**20.55**	**0.21**	**0.049**	**14.75**	**7.37**	**0.14**	**3.04E-03**

Horsepower of the engine, *HP*:

ERG determined an average horsepower per pumpjack engine (20.55 Hp) by assuming that all pumpjack engines located in Texas were of the Arrow C series types listed in Table 4-11, with the engine population distributed evenly across the four engine models.

Load factor of the engine while operating, *LF*:

A 2006 study entitled: “Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico” (Pollack, et al., 2006) assumed the maximum power delivered by a pumpjack engine to be 100 percent of available engine power and the minimum power to be a 10 percent load representative of idling. With these bounds and the approximate form of the power curve, the report estimated an average loading of 71 percent. For this 2008 inventory, ERG also used 71 percent as the load factor.

Annual number of hours the engine is used, t_{annual}:

The 2006 New Mexico study assumed that pumpjack engines operate nearly without interruption year-round (8,760 hours per year). However, this assumption would likely be an over estimate for Texas pumpjack engines as many of the oil wells located in Texas have intermittent activity and are not producing oil 24 hours per day. For this reason, ERG assumed a pumpjack engine only runs half the year, or 4,380 hours. ERG also verified this assumption through phone interviews with companies specializing in artificial lit engines. For future work, ERG recommends surveying operators to verify this assumption. Another way to verify this assumption would be to use oil well production data from the TRC as well as individual oil well pumpjack engine size information (most likely from survey data) to estimate the amount of hours each engine would need to operate in order to pump the stated oil production.

HAP Emissions for Pumpjack Engines:

HAP emissions from pumpjack engines were calculated using VOC and PM speciation data as follows:

$$E_{VOC\text{-}HAP} = E_{VOC} \text{ x } (E_{\%VOC\text{-}HAP} /100)$$

where:

$E_{VOC\text{-}HAP}$ = Speciated VOC-HAP emissions [tons/yr]
E_{VOC} = VOC emissions [tons/yr]
$E_{\%VOC\text{-}HAP}$ = % HAP composition of VOC emissions

and

$$E_{PM\text{-}HAP} = E_{PM} \text{ x } (E_{\%PM\text{-}HAP} /100)$$

where:

$E_{PM\text{-}HAP}$ = Speciated PM-HAP emissions [tons/yr]
E_{PM} = PM emissions [tons/yr]
$E_{\%PM\text{-}HAP}$ = % HAP composition of PM emissions

Appendix C contains the VOC and PM HAP speciation data.

Emissions for county i, and pollutant k, E_{ik}:

Appendix E presents county-level pumpjack engine emissions corresponding to the number of active oil wells located in each county, based on the input variables discussed above.

Example Calculation for Pumpjack Engines

Using the equation provided above, ERG calculated NO_x emissions in Anderson County from pumpjack engines as follows:

where:

$$E_{ik} = W_i \times f_{pumpjack} \times \left(1 - e_{pumpjack}\right) \times \left(\frac{EF_k * HP * LF * t_{annual}}{907{,}180} \right)$$

E_{ik} = NO_x emissions in Anderson County [tons/yr]
W_i = 456 (the total number of active oil wells in Anderson County) [wells]
$f_{pumpjack}$ = 1 (the fraction of oil wells in Anderson County with artificial lift engines)
$e_{pumpjack}$ = 0.70 (the fraction of artificial lift engines in Anderson County that are electrically operated)
EF_k = 14.75 (the emission factor for NO_x) [g/Hp-hr]
HP = 20.55 (the horsepower of the engine) [Hp]
LF = 0.71 (the load factor of the engine while operating)
t_{annual} = 4,380 (is the annual number of hours the engine is used) [hr/yr]
907,180 is the conversion factor from grams to tons of emissions

Therefore:
E_{ik} = 456 x 1 x (1 - 0.70) x ((14.75 [g NO_x/Hp-hr] x 20.55 [Hp] x 0.71 x 4,380 [hr/yr])/907,180))
E_{ik} = 142.14 [tons NO_x/yr]

4.3 Dehydrators

A dehydrator is used to remove moisture from produced raw natural gas prior to transferring it to the gas transmission pipeline. Dehydrators operate by contacting the natural gas with a hygroscopic liquid such as triethylene glycol. The water vapor in the gas stream becomes dissolved in the glycol liquid solvent, removing the water from the natural gas. During the absorption process, the glycol also absorbs some methane and VOC. The glycol is then depressurized in a flash vessel and the water vapor is removed from the glycol in a glycol regenerator. Some dehydrators do not employ a flash vessel. In those dehydrators, depressurization occurs in the regenerator. Methane, VOC, and HAPs are emitted from the dehydrator during both of these steps.

Depending upon the dehydrator equipment, these emissions may be recaptured and recycled, or controlled by flaring. Not all dehydrators are controlled. The glycol is normally circulated by use of electric pumps. The glycol regeneration process requires heating the glycol-water mixture in a glycol regenerator boiler. The regenerator boiler has similar emissions characteristics to typical combustion units. On-site gas is typically used as the fuel resulting in emissions of CO and NO_x.

4.3.1 *Dehydrator Flash Vessels and Regenerator Vents*

Emissions from dehydrator flash vessels and regenerator vents were calculated using a methodology similar to that employed in the 2008 CENRAP study (Bar-Ilan, et al., 2008). In place of the CENRAP emission factors, ERG derived estimates of dehydrator emission factors for VOC, benzene, toluene, ethylbenzene, and xylene from emissions data submitted to TCEQ by operators of dehydrators in use at point sources in Texas. For this 2008 inventory, ERG calculated county-level emissions from dehydrator flash vessel and glycol regenerator vent emissions with the following equation:

$$E_{ik} = TGP_i \times EF_k \times \left(\frac{1}{2,000} \right)$$

where:

E_{ik} is the emissions for county i, and pollutant k [tons/yr]
TGP_i is the total production of natural gas from gas wells in county i [MMscf/yr]
EF_k is the emission factor for pollutant k [lb/MMscf]
2,000 is the conversion factor from pounds to tons of emissions

Total production of natural gas from gas wells in county i, TGP_i:

Natural gas production data by county (TGP_i) was provided for 2008 by the TRC. 57 counties had no gas production in 2008.

Emission factor for pollutant k, EF_k:

In place of the CENRAP emission factors, ERG derived estimates of dehydrator emission factors for VOC, benzene, toluene, ethylbenzene, and xylene from emissions data submitted to TCEQ by operators of dehydrators in use at point sources in Texas. These emissions estimates were prepared by the operators using Gly-Calc software. Data on the presence of flash vessels, control devices, and control efficiencies was also derived from the TCEQ emissions data, indicating that a wide variety of equipment configurations, as well as control technologies, are in use for natural gas production in Texas. There were 82 complete samples in the dataset, spanning the full range of gas-producing regions in Texas. Statewide weighted averages for these five pollutants were derived from the emissions data, and are shown in Table 4-12 below.

These emission factors may produce emissions estimates that are lower than actual emissions at the area-source dehydrators in the state. TCEQ recognizes that the types of control technologies in use at dehydrators located at point sources may be different than the control technologies in use at dehydrators located at smaller area sources. Control requirements are different and incentives for recapturing and/or controlling VOC and HAP emissions may be different for operators of (larger) point sources and (smaller) area sources. However, this dataset of dehydrator emissions represents the full range of uncontrolled and controlled dehydrators in Texas and is a good composite representation of statewide dehydrator emissions.

Table 4-12. Statewide Emission Factors for VOC, Benzene, Toluene, Ethylbenzene, and Xylene from Dehydrator Flash Vessels and Regenerator Vents in Texas

Pollutant	Emission Factor (lb/MMscf)	Number of Samples
VOC	1.63	82
Benzene	0.38	68
Toluene	0.20	64
Ethylbenzene	0.02	45
Xylene	0.75	60

Emissions for county i, and pollutant k, E_{ik}:

Appendix E presents county-level dehydrator flash vessel and regenerator emissions corresponding to the production of natural gas at wells located in each county, based on the input variables discussed above.

Example Calculation for Dehydrator Flash Vessels and Regeneration Vents

Using the equation provided above, ERG calculated Benzene emissions in Anderson County from dehydrator flash vessels and regeneration vents as follows:

$$E_{ik} = TGP_i \times EF_k \times \left(\frac{1}{2{,}000} \right)$$

where:

E_{ik} = (the Benzene emissions for Anderson County) [tons/yr]
TGP_i = 12,045 (the total production of natural gas from gas wells in Anderson County) [MMCF/yr]
EF_k = 0.38 (the emission factor for Benzene) [lb/MMscf]

2,000 is the conversion factor from pounds to tons of emissions

Therefore:

E_{ik} = 12,045 [MMCF/yr] x 0.38 [lb/MMscf] x (1/2,000)
E_{ik} = 2.29 [tons/yr]

4.3.2 *Glyol Regenerator Boilers*

Emissions from glycol regenerator boilers were calculated using the methodology and emission factors employed in the 2008 CENRAP study (Bar-Ilan, et al., 2008). For this 2008 inventory, ERG calculated county-level emissions from dehydrator regenerator boilers with the following equation:

$$E_{ik} = TGP_i \times EF_k \times \left(\frac{1}{2{,}000}\right)$$

where:

E_{ik} is the emissions for county i, and pollutant k [tons/yr]
TGP_i is the total production of natural gas from gas wells in county i [MMscf/yr]
EF_k is the emission factor for pollutant k [lb/MMscf]
2,000 is the conversion factor from pounds to tons of emissions

Total production of natural gas from gas wells in county i, TGP_i:

Natural gas production data by county (TGP_i) was provided for 2008 by the TRC. 57 counties had no gas production in 2008.

Emission factor for pollutant k, EF_k:

ERG used the CENRAP emission factors for regenerator boiler emissions. The CENRAP emission factors are in terms of pounds of pollutant emitted for each million cubic feet (MMscf) of gas produced. These emission factors are shown in Table 4-13 below.

Table 4-13. Emission Factors for NO_x and CO Emissions from Dehydrator Regenerator Boilers

Pollutant	Emission Factor (lb/MMscf)
NO_x	0.052
CO	0.105

Emissions for county i, and pollutant k, E_{ik}:

Appendix E presents county-level dehydrator regenerator boiler emissions corresponding to the production of natural gas at wells located in each county, based on the input variables discussed above.

Example Calculation for Glycol Regenerator Boilers:

Using the equation provided above, ERG calculated NO_x emissions in Anderson County from glycol regenerator boilers as follows:

$$E_{ik} = TGP_i \times EF_k \times \left(\frac{1}{2,000} \right)$$

where:

E_{ik} = NO_x emissions in Anderson County [tons/yr]
TGP_i = 12,045 (the total production of natural gas from gas wells in Anderson County) [MMscf/yr]
EF_k = 0.052 (the emission factor for NO_x) [lb/MMscf]
2,000 is the conversion factor from pounds to tons of emissions

Therefore:

E_{ik} = 12,045 [MMscf/yr] x 0.052 [lb/MMscf] x (1/2,000)
E_{ik} = 0.31 [tons NO_x/yr]

4.3.3 *Dehydrator Emission Control Device*

Emissions from dehydrator control devices were calculated using the basic methodology employed in the 2008 CENRAP study (Bar-Ilan, et al., 2008). Like the 2008 CENRAP study, ERG used the emission factors from AP 42, Chapter 13.5 for NO_x and CO. ERG also used the heat value of the gas flared from the CENRAP study. ERG derived estimates of the amount of gas flared for each unit of gas produced from the emissions data submitted to TCEQ by operators of dehydrators in use at point sources in Texas. For this 2008 inventory, ERG calculated county-level emissions from dehydrator emission control devices with the following equation:

$$E_{ik} = TGP_i \times f_{flared} \times \frac{1}{D} \times HV \times EF_k \times \frac{1}{2,000}$$

where:

E_{ik} is the emissions for county i, and pollutant k [tons/yr]
TGP_i is the total production of natural gas from gas wells in county i [MMscf/yr]
F_{flared} is the fraction of produced gas that is flared [lbs flared/MMscf produced]
D is the density of the gas flared [lbs/MMscf]

HV is the heat value of the gas flared [MMBtu/MMscf]
EF_k is the emission factor for pollutant k [lbs/MMBtu]
2,000 is the conversion factor from pounds to tons of emissions

Total production of natural gas from gas wells in county i, TGP_i:

Natural gas production data by county (TGP_i) was provided for 2008 by the TRC. 57 counties had no gas production in 2008.

Fraction of produced gas that is flared, F_{flared}:

ERG derived estimates of the amount of gas flared for each unit of gas produced from the emissions data submitted to TCEQ by operators of dehydrators in use at point sources in Texas. The sum of the reported emissions from flash vessels and regenerator vents before controls, in tons of total hydrocarbons, was tallied for all 82 samples in the dataset. This figure was compared with the total production of natural gas reported in those 82 samples, producing a weighted average. Because emissions are reported in pounds, and production is reported in Millions of standard cubic feet (MMscf), the units for this fraction are pounds of gas flared per million standard cubic feet of gas produced (lbs flared/MMscf produced). The dehydrator emissions data indicated that 1 ton (2,000 pounds) of gas is flared for each 149.2 million standard cubic feet (MMscf) of gas produced.

Density of the gas flared, D:

ERG derived estimates of the density of the gas flared by assuming it was equivalent to the density of the dry gas produced by the dehydrator. This data was taken from the dehydrator emissions reports submitted to TCEQ. The amount of dry gas produced, in pounds per hour, was divided by the flow rate of gas produced, in cubic feet per hour, producing a density for dry gas in units of pounds per cubic foot. The sum of the amount of dry gas produced was tallied for all 82 samples in the dataset, and was divided by the sum of the flow rate of gas produced, producing a weighted average, with units of pounds per standard cubic foot (lbs/scf). This figure was then multiplied by 10^6 standard cubic feet per MMscf, to yield a factor with units of pounds per million standard cubic feet (lbs/MMscf). The dehydrator emissions data indicated that the density of the gas produced is 0.047 pounds per standard cubic foot or 46,952 (lbs/MMscf).

Heat value of the gas flared, *HV*:

The heat value of the gas flared is taken from the 2008 CENRAP study. This value is equivalent to 1,209 Btu per standard cubic feet of gas (Btu/scf).

Emission factor for pollutant k, EF_k:

ERG used the CENRAP emission factors for dehydrator control emissions. Although the dehydrator emissions data from TCEQ showed that a small percentage of dehydrator flash vessel and regenerator vent emissions are controlled by incinerators, the vast majority (over 90%) are burned in flares. ERG chose to use the simplifying assumption that all dehydrator flash vessel and regenerator vent emissions that are controlled by combustion are directed to flares. The emission factors for flares are taken directly from AP 42, Chapter 13.5. The emission factors are in terms of pounds of pollutant emitted for each million Btu (lbs/MMBtu) of gas flared. These emission factors are shown in Table 4-14 below.

Table 4-14. Emission Factors for NO_x and CO Emissions from Dehydrator Controls (Flares)

Pollutant	Emission Factor (lb/MMBtu)
NO_x	0.068
CO	0.37

Emissions for county i, and pollutant k, E_{ik}:

Appendix E presents county-level dehydrator control emissions corresponding to the production of natural gas at wells located in each county, based on the input variables discussed above.

Example Calculation for Dehydrator Controls:

Using the equation provided above, ERG calculated NO_x emissions in Anderson County from dehydrator controls as follows:

$$E_{ik} = TGP_i \times f_{flared} \times \frac{1}{D} \times HV \times EF_k \times \frac{1}{2,000}$$

where:

E_{ik} = NO_x emissions for Anderson County [tons/yr]
TGP_i = 12,045 (the total production of natural gas from gas wells in Anderson County) [MMscf/yr]
F_{flared} = 13 (the fraction of produced gas that is flared) [lbs flared/MMscf produced]
D = 46,952 (the density of the gas flared) [lbs/MMscf]
HV = 1,209 (the heat value of the gas flared) [MMBtu/MMscf]
EF_k = 0.068 (the NO_x emission factor) [lbs/MMBtu]
2,000 is the conversion factor from pounds to tons of emissions

Therefore:

E_{ik} = 12,045 [MMscf/yr] x 13.41 [lbs flared/MMscf produced] x (1/46,952 [lbs/MMscf]) x 1,209 [MMBtu/MMscf] x 0.068 [lbs/MMBtu] x (1/2,000)
E_{ik} = 0.14 [tons NO_x/yr]

4.4 Oil and Condensate Storage Tanks

Storage tanks are used in a variety of applications in the oil and gas industry. An oil and gas well may produce oil, natural gas, or a mixture of the two. When oil and gas are brought to the surface, the liquids produced may contain a mixture of liquid and gaseous organic compounds, nitrogen, carbon dioxide, water, sand, and other impurities. The mixture is typically passed through a three-phase separator, which allows the water, oil and gas to separate. The liquid oil and water components are then piped to storage tanks. If the well produces gas, it is possible that liquids may condense out of the gas as the pressure is decreased. The hydrocarbon liquid produced at gas wells is known as condensate. Oil and condensate are piped to storage tanks until they can be transported offsite. Tanks are typically vented to the atmosphere.

Oil and condensate storage tank emissions at wellhead and gathering sites are composed of flashing losses, working losses, and breathing losses. Flashing losses occur when a produced liquid (crude oil or condensate) with entrained gases experiences a pressure drop, as during the transfer of liquid hydrocarbons from a wellhead or separator to a storage tank. As the pressure on the liquid drops, some of the lighter compounds dissolved in the liquid are released or "flashed". Some compounds that are liquids at the initial pressure and temperature, change phase from a liquid to a gas and are also released or "flashed" from the liquid in the storage tank. Working losses occur when vapors are displaced from a tank during the filling and unloading cycles, and when the fluid is agitated during filling of the tank. Breathing losses (also called standing losses) occur due to the normal evaporation of liquid in a tank. Breathing losses are vapors that are produced in response to the daily temperature change.

Emissions from oil and condensate storage tanks were calculated using the methodology and emission factor data developed in the 2009 TERC study "VOC Emissions From Oil and Condensate Storage Tanks" (TERC, 2009). These emission factors were multiplied by county-specific oil and gas production data obtained from the TRC. The calculations assume that venting emissions are uncontrolled by flares or vapor recovery units. For this 2008 inventory, ERG calculated county-level emissions from oil storage tank and condensate storage tank vent emissions with the following equations:

$$E_{ik} = TOP_i \times EF_{ik} \times \left(\frac{1}{2{,}000} \right)$$

and

$$E_{ik} = TCP_i \times EF_{ik} \times \left(\frac{1}{2{,}000} \right)$$

where:

E_{ik} is the emissions for county i, and pollutant k [tons/yr]
TOP_i is the total production of oil from oil wells in county i [BBL/yr]
TCP_i is the total production of condensate from gas wells in county i [BBL/yr]
EF_{ik} is the emission factor for county i, and pollutant k [lb/BBL]
2,000 is the conversion factor from pounds to tons of emissions

Total production of oil from oil wells in county i, TOP_i:

Oil production data by county (TOP_i) was provided for 2008 by the TRC. 42 counties had no oil production in 2008.

Total production of condensate from gas wells in county i, TCP_i:

Condensate production data by county (TOP_i) was provided for 2008 by the TRC. 80 counties had no condensate production in 2008.

Emission factor for county i, and pollutant k, EF_{ik}:

VOC Emission Factors: The VOC emission factors for oil storage tank batteries and condensate storage tank batteries are taken from the 2009 TERC study and are in units of pounds per barrel of oil/condensate produced and are shown in Table 4-15 below.

HAP Emission Factors: Benzene, toluene, ethylbenzene, and xylene are a constituent of the vapors emitted from oil and condensate storage tanks. The benzene, toluene, ethylbenzene, and xylene emission factors are derived from the data published in the 2009 TERC study. Tables 3-4 and 3-5 in the TERC study showed the measured vent gas speciation profiles for oil tanks and condensate tanks, respectively. This data was used in combination with the measured weight percent VOC data from those same tables and the VOC emission factors taken from that study to calculate emission factors for benzene, toluene, ethylbenzene, and xylene from both oil and condensate storage tanks in terms of lbs per barrel of oil or condensate produced. These emission factors are in units of pounds per barrel of oil/condensate produced and are shown in Table 4-15 below.

Table 4-15. Emission Factors for VOC, Benzene, Toluene, Ethylbenzene, and Xylene from Oil Storage Tanks and Condensate Storage Tanks in Texas

Pollutant	**Emission Factors (lb/BBL)**	
	Oil	Condensate
VOC	1.60	33.3
Benzene	0.00533	0.187
Toluene	0.0083	0.319
Ethylbenzene	0.003	0.018
Xylene	0.012	0.141

Emissions for county i, and pollutant k, E_{ik}:

Appendix E present county-level oil storage tank and condensate storage tank vent emissions corresponding to the production of oil and condensate at oil wells and natural gas wells located in each county, based on the input variables discussed above.

Example Calculation for Oil and Condensate Storage Tanks:

Using the equation provided above, ERG calculated VOC emissions in Anderson County from oil storage tanks as follows:

$$E_{ik} = TOP_i \times EF_{ik} \times \left(\frac{1}{2{,}000}\right)$$

where:

E_{ik} = VOC emissions for Anderson County [tons/yr]
TOP_i = 678,901 (the total production of oil from oil wells in Anderson County) [BBL/yr]
EF_{ik} = 1.60 (the VOC emission factor for Anderson County) [lb/BBL]

2,000 is the conversion factor from pounds to tons of emissions

Therefore:

E_{ik} = 678,901 [BBL/yr] x 1.6 [lb/BBL] x (1/2,000)

E_{ik} = 543 [tons/yr]

4.5 Oil and Condensate Loading

Oil and condensate stored in field storage tanks is transferred to trucks and railcars and shipped to refineries for further processing. Fugitive VOC emissions are released from these loading processes as the vapors in the receiving vessel are displaced by the liquids from the storage tanks. These vapors are normally vented to the atmosphere.

Emissions from oil and condensate loading were calculated using the emission estimation methodology in the 2009 TCEQ study. This methodology is taken from AP 42, Chapter 5.2 - Transportation and Marketing of Petroleum Liquids. Emission factors for loading losses were calculated at the county level. These emission factors were multiplied by county-specific 2008 oil and condensate production data obtained from the TRC to derive county-specific emission estimates. ERG obtained monthly temperature data for the counties in which the oil and condensate are produced. Per the 2007 TCEQ study, ERG used AP-42 data for crude oil (50 lb/lb-mole) at 60 degrees F to approximate the molecular weight of tank vapors for oil. ERG used AP-42 data for gasoline (Reid Vapor Pressure (RVP) 7) (68 lb/lb-mole) at 60 degrees F to approximate the molecular weight of tank vapors for condensate. The AP-42 equation was used to calculate temperature-dependent emission factors for loadout losses for each county. Truck or railcar loading emissions were calculated by multiplying the emission factor by county-level oil and condensate production data. The calculations assume that venting emissions are uncontrolled by flares or vapor recovery units. The AP-42 equation to calculate loading emission factors is shown in the following equation.

$$LL_{ik} = 12.46 \times \left(\frac{S * P_i * M}{T_i} \right)$$

where:

LL_{ik} is the loading loss [lb/1,000 gal of liquid loaded] for county i, and pollutant k
S is the saturation factor (based on type of loading operation)
P_i is the true vapor pressure of liquid loaded [psia] for county i
M is the molecular weight of tank vapors [lb/lb-mole]
T_i is the temperature of bulk liquid loaded [^{o}R] for county i

Saturation factor, *S*:

The saturation factor is taken from Table 5.2-1 of Chapter 5.2 of AP-42 and is based on submerged or splash loading of liquid with dedicated vapor balance service. This assumes that tank vapors from the truck or railcar being loaded are vented back into the tank being emptied.

True vapor pressure of the liquid being loaded, for county i, P_i:

The true vapor pressure for oil is estimated to be equivalent to the true vapor pressure for crude oil RVP 5. The true vapor pressure for condensate is estimated to be equivalent to the true vapor pressure for gasoline RVP 7. The true vapor pressure for these liquids at various temperatures are shown in Table 4-16 below. The true vapor pressure for the county-specific average temperature is calculated for oil loading with the equation.

$$P_i = (0.057 \times T_i) - 0.58$$

where:

P_i is the true vapor pressure of liquid loaded [psia] for county i
T_i is the temperature of bulk liquid loaded [^{o}F] for county i

The true vapor pressure for the county-specific average temperature is calculated for condensate loading with the equation.

$$P_i = (0.077 \times T_i) - 1.03$$

where:

P_i is the true vapor pressure of liquid loaded [psia] for county i
T_i is the temperature of bulk liquid loaded [^{o}F] for county i

These formulas are derived from linear interpolation of the slope and intercept of the line formed between the values for the true vapor pressure of crude oil RVP 5 (representing oil) and gasoline RVP 7 (representing condensate) at 55 degrees Fahrenheit and 75 degrees Fahrenheit.

Molecular weight of the tank vapors, *M*:

The molecular weight of the tank vapors for oil is estimated to be equivalent to the molecular weight of crude oil RVP 5. The molecular weight of the tank vapors for condensate is estimated to be equivalent to the molecular weight of gasoline RVP 7. The molecular weight of these liquids at 60 degrees Fahrenheit are shown in Table 4-16 below. The data in Table 4-16 is taken directly from AP-42, Chapter 7.1.

Table 4-16. Molecular Weight and True Vapor Pressure of Selected Petroleum Liquids

Petroleum Liquid	Molecular Weight at 60° F (lb/lb-mole)	True Vapor Pressure (psia)						
		40° F	50° F	60° F	70° F	80° F	90° F	100° F
Crude Oil RVP 5	50	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Gasoline RVP 7	68	2.3	2.9	3.5	4.3	5.2	6.2	7.4

Temperature of the bulk liquid loaded, T_i:

The average 2008 temperature data, degrees Fahrenheit, for 115 Texas counties was obtained from the National Weather Service and from several state/local monitoring sites. These data were used to estimate the average temperature in the adjacent 139 counties. The average liquid temperature is assumed to be equivalent to the average ambient air temperature.

Loading loss for county i, and pollutant k, LL_{ik}:

The loading loss is the county-specific emission factor and has units of pounds per 1,000 gallons of oil or condensate loaded (lbs/1,000 gal).

For this 2008 inventory, ERG calculated county-level emissions from oil loading emissions and condensate loading emissions with the following equations:

$$E_{ik} = TOP_i \times LL_k \times 42 \times \left(\frac{1}{2{,}000}\right)$$

and

$$E_{ik} = TCP_i \times LL_{ik} \times 42 \times \left(\frac{1}{2{,}000}\right)$$

where:

E_{ik} is the loading emissions for county i, and pollutant k [tons/yr]
TOP_i is the total production of oil from oil wells in county i [BBL/yr]
TCP_i is the total production of condensate from gas wells in county i [BBL/yr]
LL_{ik} is the loading loss (emission factor) for pollutant k [lb/1,000 gal loaded]
42 is the conversion factor from barrels to gallons
2,000 is the conversion factor from pounds to tons of emissions

Total production of oil from oil wells in county i, TOP_i:

Oil production data by county (TOP_i) was provided for 2008 by the TRC. 42 counties had no oil production in 2008.

Total production of condensate from gas wells in county i, TCP_i:

Condensate production data by county (TOP_i) was provided for 2008 by the TRC. 80 counties had no condensate production in 2008.

Loading loss, LL_{ik}:

The loading loss is the emission factor calculated above and has units of pounds per 1,000 gallons of oil or condensate loaded.

HAP Emission Factors: Benzene, toluene, ethylbenzene, and xylene are a constituent of the vapors emitted during oil and condensate loading. The benzene, toluene, ethylbenzene, and xylene emission factors for oil loading and condensate loading in all oil and gas producing basins in Texas are derived from the data published in the 2009 TERC study. Tables 3-4 and 3-5 in the TERC study showed the measured vent gas speciation profiles for oil tanks and condensate tanks, respectively. This data was used in combination with the measured weight percent VOC data from those same tables and the VOC emission factors taken from that study to calculate emission factors for benzene, toluene, ethylbenzene, and xylene from both oil and condensate loading. These emission factors are in terms of units of HAP emitted per units of VOC emitted. and are shown in Table 4-17 below.

Table 4-17. Emission Factors for Benzene, Toluene, Ethylbenzene, and Xylene from Oil and Condensate Loading in Texas

Pollutant	All Texas Basins Emission Factors (lb HAP/lb VOC)	
	Oil	Condensate
Benzene	0.0033	0.2808
Toluene	0.0052	0.479
Ethylbenzene	0.00187	0.027
Xylene	0.0075	0.212

Loading emissions for county i, for pollutant k, E_{ik}:

Emissions for oil and condensate loading racks for each county are calculated by multiplying a county-specific loading loss factor by the county-specific oil and condensate production. Appendix E present county-level oil condensate loading rack emissions corresponding to the production of oil and condensate at oil wells and natural gas wells located in each county, based on the input variables discussed above.

Example Calculation for Oil and Condensate Loading:

Using the equations provided above, ERG calculated VOC emissions in Anderson County from oil loading as follows:

$$LL_{ik} = 12.46 \times \left(\frac{S * P_i * M}{T_i} \right)$$

where:

LL_{ik} = (the loading loss [lb/1,000 gal of liquid loaded] for Anderson County, and pollutant k)
S = 1.00 (the saturation factor (based on type of loading operation))
P_i = 3.1 (the true vapor pressure of liquid loaded for Anderson County) [psia]
M = 50 (the molecular weight of tank vapors) [lb/lb-mole]
T_i = 524.27 (the temperature of bulk liquid loaded for Anderson County) [^{o}R]

$$E_{ik} = TOP_i \times LL_k \times 42 \times \left(\frac{1}{2{,}000} \right)$$

where:

E_{ik} = loading VOC emissions for county i, and pollutant k [tons/yr]
TOP_i = 678,901 (the total production of oil from oil wells in Anderson County) [BBL/yr]
LL_{ik} = the loading loss (emission factor) for VOC [lb/1,000 gal loaded]
42 is the conversion factor from barrels to gallons
2,000 is the conversion factor from pounds to tons of emissions

Therefore:

LL_{ik} = 12.46 x ((1.00 x 3.1 [psia] x 50 [lb/lb-mole])/524.27 [°R])
LL_{ik} = 3.684 [lb/1,000 gal of liquid loaded]

E_{ik} = 678,901 [BBL/yr] x 3.684 [lb/1,000 gal of liquid loaded] x 42 x (1/2,000)
E_{ik} = 52.52 [tons VOC/yr]

4.6 Well Completions

Following drilling and casing, a well must be "completed." Completion is the process which enables the well to produce oil or gas. To complete the production well, casing is installed and cemented and the drilling rig is removed from the site. As the well is completed, an initial mixture of gas, hydrocarbon liquids, water, sand, and other materials comes to the surface. Standard practice during the completion process has been to vent or flare the natural gas released, some of which is VOC. This category addresses VOC emissions associated with the completion process at oil and gas wells. County-level emissions from this source were estimated for the purpose of this inventory.

Emissions from well completions were calculated using the methodology from the 2008 CENRAP study (Bar-Ilan, et al., 2008). Emissions from well completions are estimated on the basis of the volume of gas vented during completion and the average VOC content of that gas, obtained from a gas composition analyses. Emissions rates are evaluated at standard temperature and pressure (STP).

The calculation methodology for completion emissions follows the following equations:

$$E_{completion,i} = \left(\frac{P \times (V_{vented})}{(R / MW_{gas}) \times T \times 0.000035} \right) \times \frac{f_i}{907200}$$

where:

$E_{completion,i}$ is the emissions of pollutant i from a single completion event [ton/event]
P is atmospheric pressure [1 atm]
V_{vented} is the volume of vented gas per completion [MCF/event]
R is the universal gas constant [0.082 L-atm/mol-°K]
MW_{gas} is the molecular weight of the gas [g/mol]
T is the atmospheric temperature [298 °K]
0.000035 is the conversion factor from Mscf to liters
f_i is the mass fraction of pollutant i in the vented gas
907,200 is the conversion factor from grams to tons of emissions

The total emissions from all completions occurring in a county can be evaluated following:

$$E_{completion,TOTAL} = E_{completion,i} \times S_{county}$$

where:

$E_{completion,TOTAL}$ are the total emissions county-wide from completions [tons/year]
$E_{completion,i}$ are the completion emissions from a single completion event [tons/event]
S_{county} is the county-wide new well and recompleted well count

No data were available to account for the number of completions that were completed using green completion or add-on control technologies. While these technologies exist and are used to reduce emissions, no data is currently available to estimate the extent at which they are employed in Texas. Also, the 2008 CENRAP study did not contain data on green completions or add-on control technologies.

Volume of vented gas per completion, V_{vented}:

ERG was unable to obtain estimates for the volume of vented gas per completion from the TRC. Therefore, ERG used the average volume vented presented in the 2008 CENRAP study. This data was presented on a basin-level basis. The data obtained is summarized in Table 4-18 below.

Table 4-18. 2008 CENRAP Data for Volume of Gas Vented per Completion

Basin	Volume of Gas Vented per Completion (MCF/event)
Anadarko	1,737
Bend Arch-Fort Worth	637
East Texas	2,417
Palo Duro [a]	1,198
Permian	0
Perman/Marathon Thrust Belt [a]	1,198
Western Gulf	1,200

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

The data were applied to each county in Texas based on the county's corresponding basin.

Mass fraction for a single pollutant, f_i:

ERG used the average basin-level mass fraction for VOCs obtained from the 2008 CENRAP study (3.6% for gas wells and 14.1% for oil wells).

Number of completions controlled by flares, c_{flare} and the number of green completions, c_{green}:

ERG was unable to obtain estimates for the number of completions controlled by flares and the number of green completions. Therefore, ERG used default values presented in the 2008 CENRAP study, which was 0 for both parameters.

County-level new/recompleted well count, S_{county}:

ERG obtained county-level data for the number of new and recompleted wells from the TRC for each county included in this analysis. The TRC data indicated a total of 15,946 new/recompletions were finished in 2008. Of these, 3,032 were designated as gas wells and 2,687 were designated as oil wells. The remaining 10,227 wells were classified as O/G (as they may end up producing oil, gas or a combination of both). For the purposes of emissions calculations, ERG assigned the wells classified as O/G to the oil and gas categories by assuming that the percentage of oil and gas well completions in each county was identical to the percentage of producing oil and gas wells in each county. For example, if 75% of the producing wells in a single county were oil wells, then 75% of the wells classified as O/G were designated as oil wells. If there were no producing wells in a county, the completion was assumed to be an oil well completion to represent worst-case emissions. As a result of this analysis, there were an estimated 8,702 gas well competions and 7,244 oil well completions in 2008.

Emissions by county $E_{completion,TOTAL}$:

Appendix E presents county-level well completion emissions corresponding to the number of wells completed in each county, based on the input variables discussed above.

Example Calculation for Well Completions:

Using the equations provided above, ERG calculated VOC emissions in Anderson County from oil well completions as follows:

$$E_{completion,voc} = \left(\frac{P \times (V_{vented})}{(R / MW_{gas}) \times T \times 0.000035} \right) \times \frac{f_i}{907200}$$

where:

$E_{completion,voc}$ = the VOC emissions in Anderson County from a single oil well completion event [ton/event]
P = 1 (atmospheric pressure) [atm]
V_{vented} = 2,417 (the volume of vented gas per completion for Anderson County (East Texas Basin)) [MCF/event]
R = 0.082 (the universal gas constant) [L-atm/mol-^{o}K]
MW_{gas} = 27 (the molecular weight of the gas) [g/mol]
T = 298 (the atmospheric temperature) [^{o}K]
0.000035 is the conversion factor from Mscf to liters
f_i = 0.141 (the mass fraction of pollutant i in the vented gas)
907,200 is the conversion factor from grams to tons of emissions

Therefore:

$E_{completion,voc}$ = ((1 atm x 2,417 [MCF/event])/((0.082 [L-atm/mol-^{o}K]/27 [g/mol]) x 298 [^{o}K] x 0.000035) x 0.141/907200
$E_{completion,voc}$ = 11.86 [tons VOC/event]

The total emissions from all completions occurring in Anderson County can be evaluated following:

$$E_{completion,TOTAL} = E_{completion,voc} \times S_{county}$$

where:

$E_{completion,TOTAL}$ = the total VOC emissions from completions in Anderson County [tons VOC/year]
$E_{completion,voc}$ = 11.86 (completion emissions from a single completion event) [tons VOC/event]
S_{county} = 45.94 (the county-wide new well and recompleted well count for Anderson County) [oil well completion events/yr]

Therefore:

$E_{completion,voc}$ = 11.86 [tons VOC/event] x 50 [oil well completion events/yr]
$E_{completion,voc}$ = 544.76 [tons VOC/yr]

4.7 Wellhead Blowdowns

Wellhead blowdowns refer to the practice of venting gas from wells that have developed some kind of cap or obstruction before any additional intervention work can be done on the wells. Typically, wellhead blowdowns are conducted on wells that have been shut in for a period of time and the operator desires to bring the well back into production. Wellhead blowdowns are also sometimes conducted to remove fluid caps that have built up in producing gas wells. Because gas is directly vented from the blowdown event, blowdowns can be a source of VOC emissions. County-level emissions from this source were estimated for the purpose of this inventory.

Emissions from wellhead blowdowns were calculated using the methodology from the 2008 CENRAP study (Bar-Ilan, et al., 2008). Emissions from wellhead blowdowns are estimated on the basis of the volume of gas vented during a blowdown, and the average VOC content of that gas, obtained from a gas composition analyses. The emissions are also estimated based on the frequency of blowdowns. Emissions rates are evaluated at standard temperature and pressure (STP).

The calculation methodology for blowdown emissions is identical to the method for completion emissions, and follows the following equations:

$$E_{blowdown,i} = \left(\frac{P \times (V_{vented})}{(R / MW_{gas}) \times T \times 0.000035} \right) \times \frac{f_i}{907200}$$

where:

$E_{completion,i}$ is the emissions of pollutant i from a single blowdown event [ton/event]
P is atmospheric pressure [1 atm]
V_{vented} is the volume of vented gas per blowdown [MCF/event]
R is the universal gas constant [0.082 L-atm/mol-^{o}K]
MW_{gas} is the molecular weight of the gas [g/mol]
T is the atmospheric temperature [298 ^{o}K]
0.000035 is the conversion factor from Mscf to liters
f_i is the mass fraction of pollutant i in the vented gas
907,200 is the conversion factor from grams to tons of emissions

The total emissions from all blowdowns occurring in a county can be evaluated following:

$$E_{blowdown,TOTAL} = E_{blowdown,i} \times N_{blowdown} \times N_{wells}$$

where:

$E_{blowdown,TOTAL}$ are the total emissions county-wide from blowdowns [tons/year]
$E_{blowdown,I}$ are the blowdown emissions from a single blowdown event [tons/event]
$N_{blowdown}$ is the number of blowdowns per well in the county
N_{wells} is the total number of active wells in the county

No data were available to account for the number of blowdowns using green completion or add-on control technologies. While these technologies exist and are used to reduce emissions, no data is currently available to estimate the extent at which they are employed in Texas. Also, the 2008 CENRAP study did not contain data on green blowdowns or add-on control technologies. Therefore, we have assumed 0 for these parameters.

Volume of vented gas per blowdown, V_{vented}:

ERG was unable to obtain estimates for the volume of vented gas per blowdown from the TRC. Therefore, ERG used the average volume vented presented in the 2008 CENRAP study. This data was presented on a basin-level basis. The data obtained is summarized in Table 4-19 below.

Table 4-19. 2008 CENRAP Data for Volume of Gas Vented per Blowdown per Wellhead

Basin	Volume of Gas Vented per Blowdown per Wellhead (MCF/event/wellhead)
Anadarko	7.28
Bend Arch-Fort Worth	38.9
East Texas	31.67
Palo Duro [a]	60.35
Permian	50
Perman/Marathon Thrust Belt [a]	60.35
Western Gulf	173.9

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

The data were applied to each county in Texas based on the county's corresponding basin.

Mass fraction for a single pollutant, f_i:

ERG used the average basin-level mass fraction for VOCs obtained from the 2008 CENRAP study (3.6% for gas wells and 14.1% for oil wells).

County-level number of blowdowns per well, $N_{blowdown}$:

ERG was unable to obtain estimates for the number of blowdowns per well from the TRC. Therefore, ERG used the average volume vented presented in the 2008 CENRAP study. This data was presented on a basin-level basis. The data obtained is summarized in Table 4-20 below.

Table 4-20. 2008 CENRAP Data for Wellhead Blowdown Frequency

Basin	Blowdown Frequency (events/wellhead/yr)
Anadarko	3.3
Bend Arch-Fort Worth	1.54
East Texas	1.09
Palo Duro [a]	5
Permian	5
Perman/Marathon Thrust Belt [a]	5
Western Gulf	0.71

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

The data were applied to each county in Texas based on the county's corresponding basin.

County-level well count, N_{wells}:

ERG obtained county-level data for the number of wells from the TRC for each county included in this analysis. The TRC data (for onshore wells only) indicated a total of 91,732 gas wells and 153,831 oil wells for the State of Texas.

Number of blowdowns controlled by flares, c_{flare} and the number of green blowdowns, c_{green}:

ERG was unable to obtain estimates for the number of blowdowns controlled by flares and the number of green blowdowns. Therefore, ERG used default values presented in the 2008 CENRAP study, which was 0 for both parameters.

Emissions by county $E_{blowdown,TOTAL}$:

Appendix E presents county-level wellhead blowdown emissions corresponding to the number of wells in each county, based on the input variables discussed above.

Example Calculation for Wellhead Blowdowns

Using the equations provided above, ERG calculated VOC emissions in Anderson County from oil wellhead blowdowns as follows:

$$E_{blowdown,voc} = \left(\frac{P \times (V_{vented})}{(R / MW_{gas}) \times T \times 0.000035} \right) \times \frac{f_i}{907200}$$

where:

$E_{blowdown,voc}$ = the VOC emissions in Anderson County from a single oil wellhead blowdown event [ton/event]
P = 1 (atmospheric pressure) [atm]
V_{vented} = 31.7 (the volume of vented gas per blowdown for Anderson County (East Texas Basin)) [MCF/event]
R = 0.082 (the universal gas constant) [L-atm/mol-^oK]
MW_{gas} = 27 (the molecular weight of the gas) [g/mol]
T = 298 (the atmospheric temperature) [^oK]
0.000035 is the conversion factor from Mscf to liters
f_i = 0.141 (the mass fraction of pollutant i in the vented gas)
907,200 is the conversion factor from grams to tons of emissions

Therefore:

$E_{blowdown,voc}$ = ((1 [atm] x 31.7 [MCF/event])/((0.082 [L-atm/mol-^oK]/27 [g/mol]) x 298 [^oK] x 0.000035) x 0.141/907200
$E_{blowdown,voc}$ = 0.1554 [tons/event]

The total emissions from all blowdowns occurring in Anderson County can be evaluated following:

$$E_{blowdown,TOTAL} = E_{blowdown,voc} \times N_{blowdown} \times N_{wells}$$

where:

$E_{blowdown,TOTAL}$ = the total VOC emissions county-wide from blowdowns [tons/year]
$E_{blowdown,voc}$ =0.1554 (the VOC blowdown emissions from a single blowdown event) [tons/event]
$N_{blowdown}$ =1.09 (the number of blowdowns per well in Anderson County (East Texas Basin)) [events/wellhead/yr]
N_{wells} = 456 (the total number of active wells in Anderson County) [wells]

Therefore:

$E_{blowdown,\ TOTAL}$ = 0.1554 [tons VOC/event] x 1.09 [events/wellhead/yr] x 456 [wells]
$E_{blowdown,\ TOTAL}$ = 77.24 [tons VOC/yr]

4.8 Pneumatic Devices

Pneumatic devices are used for a variety of gas well processes and are powered by high-pressure produced gas. These devices include transducers, liquid level controllers, pressure controllers and positioners. During the normal operation of these devices, they release or bleed natural gas to the atmosphere making them a source of VOC emissions. County-level emissions from these sources are estimated for the purpose of this inventory.

Emissions from pneumatic devices were calculated using the methodology from the 2008 CENRAP study (Bar-Ilan, et al., 2008). In this emission estimation approach, emissions from pneumatic devices at a single well site are calculated using the following equation:

$$E_{pneumatic,j} = \frac{f_j}{907200}\left(\sum_i V_i \times N_i \times t_{annual}\right) \times \frac{P}{\left(\frac{R}{MW_{gas}}\right) \times T \times 0.000035}$$

where:

$E_{pneumatic,j}$ is the total emissions of pollutant j from all pneumatic devices for a typical well [ton/well-year]
907,200 is the conversion factor from grams to tons of emissions
f_j is the mass fraction of pollutant j in the vented gas
V_i is the volumetric bleed rate from device i [scf/hr/device]
N_i is the total number of device i owned by the participating companies
t_{annual} is the number of hours per year that devices are operating
P is the atmospheric pressure [1 atm]
R is the universal gas constant [0.082 L-atm/mol-^{o}K]
MW_{gas} is the molecular weight of the gas [g/mol]
T is the atmospheric temperature [298 ^{o}K]
0.000035 is the conversion factor from Mscf to liters

County-wide emissions are calculated using the following equation:

$$E_{pneumatic,TOTAL} = E_{pneumatic,j} \times N_{well}$$

where:

$E_{pneumatic,TOTAL}$ is the total pneumatic device emissions in the county [ton/yr]
$E_{pneumatic,j}$ is the pneumatic device emissions for a single well of pollutant j [ton/yr]
N_{well} is the total number of active wells in the county for a given year

Emissions rates are evaluated at STP.

Number of active wells in a given county for 2008, N_{well}:

Total active wells by county for the full 2008 year are not readily available from the TRC website. However, well distribution data by county is available from the TRC website on a bi-annual (February and September) basis and can be found at: http://www.rrc.state.tx.us/data/wells/wellcount/index.php. ERG used the September 2008 TRC report to get a count of regular producing wells by county.

Volumetric bleed rate from device i, V_i:

Bleed rates for various devices are presented in a 2004 EPA Natural Gas Star program study. We have used these when calculating emissions from pneumatic devices at gas production sites. This data is summarized in Table 4-21.

Total number of devices, N_i:

The 2008 CENRAP study obtained basin-level data for the total number of devices per well from survey data. The same value for each device type was used for each basin in the CENRAP report. ERG used this basin level data as a basis for the number of devices per well. This data is summarized in Table 4-21.

Number of hours per year that devices are operating, t_{annual}:

ERG has assumed the annual operating hours for these devices is 8,760.

Molecular weight of gas, MW_{gas}:

The 2008 CENRAP study obtained basin-level data for the gas molecular weight from survey data. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. ERG used this basin level data as a basis for the gas molecular weight. ERG calculated a weighted average based on the total number of wells in each basin. This data is summarized in Table 4-21.

Mass fraction of pollutant j in the vented gas, f_j:

The 2008 CENRAP study obtained basin-level data for the mass fraction of VOC from survey data. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. ERG used this basin level data as a basis for the VOC mass fraction. ERG calculated a weighted average based on the total number of wells in each basin. This data is summarized in Table 4-21.

Table 4-21. CENRAP Basin-Level Data for Pneumatic Devices at Gas Wells

	Number of Devices/Bleed Rate (scf/hr)					Gas Molecular Weight (g/mol)	VOC Content (fraction)
Basin	**Liquid Level Controller**	**Positioner**	**Pressure Controller**	**Transducer**	**Other**		
Anadarko	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	21	0.1
East Texas	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	19	0.13
Fort Worth	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	19	0.14
Permian	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	19	0.14
Western Gulf	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	19	0.02
Palo Duro[a]	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	20	0.11
Marathon Thrust Belt[a]	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	20	0.11
Weighted Average	2 / 31	0 / 15.2	1 / 16.8	0 / 13.6	0 / 0	19.68	0.1054

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

Emissions by county $E_{pneumatic,TOTAL}$:

Appendix E presents county-level pneumatic device emissions corresponding to the number of active oil and gas wells in each county, based on the input variables discussed above.

Example Calculation for Pneumatic Devices:

Using the equations provided above, ERG calculated VOC emissions in Anderson County from pneumatic devices as follows:

For one well:

$$E_{pneumatic,j} = \frac{f_j}{907200}\left(\sum_i V_i \times N_i \times t_{annual}\right) \times \frac{P}{\left(\frac{R}{MW_{gas}}\right) \times T \times 0.000035}$$

Where:

$E_{pneumatic,j}$ = VOC emissions from one well in Anderson County [tons/well-year]
907,200 is the conversion factor from grams to tons of emissions
f_j = 0.1054 (the VOC fraction in the vented gas in Anderson County)
V_i = 0.031 for liquid level controllers and 0.0168 for pressure controllers (bleed rate for devices present in wells in Anderson County) [Mcf/device-hr]
N_i = 2 for liquid level controllers and 1 for pressure controllers (number of devices present in wells in Anderson County)
t_{annual} = 8,760 (annual operating hours of wells in Anderson County) [hr/yr]
P = 1 (standard pressure) [atm]
T = 298 (standard temperature) [^{o}K]
R = 0.082 (universal gas constant) [L-atm/mol-^{o}K]
MW_{gas} = 19.68 (molecular weight of vented gas at wells in Anderson County) [g/mol]
0.000035 is the conversion factor from Mscf to liters

Therefore:

$E_{pneumatic,j}$ = (0.1504/907,200) x ((0.031 [Mcf/device-hr] * 2 [devices] * 8,760 [hrs]) + (0.0168 [MCF/device-hr] * 1 [device] * 8,760 [hrs])) x (1/((0.082 [L-atm/mol-^{o}K] / 19.68 [g/mol]) * 298 [^{o}K] * 0.000035))
$E_{pneumatic,j}$ = 1.845 [tons VOC/well-yr]

For all wells in Anderson County:

$$E_{pneumatic,TOTAL} = E_{pneumatic,j} \times N_{well}$$

Where:

$E_{pneumatic,TOTAL}$ = VOC emissions from all gas wells in Anderson County [tons/yr]
$E_{pneumatic,j}$ = 1.845 [tons VOC/well-yr]
N_{well} = 133 (number of wells in Anderson County)

Therefore:

$E_{pneumatic,TOTAL}$ = 1.845 [tons VOC/well-yr] x 133 [wells]
$E_{pneumatic,TOTAL}$ = 245 [tons VOC/yr]

4.9 Fugitive Emissions (Equipment Leaks)

All oil and gas producing sites have a system of pumps and piping to transport oil and gas from the wellhead to the processing area. These pumps and piping networks are constructed with many individual components including flanges, valves, seals, and connectors. As a result of high operating pressures, varying fitting tightness, and age and condition, each of these components has the potential to release fugitive emissions while oil and gas product flows through them. County-level emissions from these sources are estimated for the purpose of this inventory.

Emissions from fugitive components were calculated using the methodology from the 2008 CENRAP study (Bar-Ilan, et al., 2008). In this methodology, fugitive emissions from a single well site may be calculated using the following equation:

$$E_{fugitive,j} = \sum_i EF_i \times N_i \times t_{annual} \times Y_j \times 0.0011$$

where:

$E_{fugitive,j}$ is the fugitive emissions for a single typical well for pollutant j [ton/yr/well]
EF_i is the emission factor of Total Organic Carbon (TOC) for a single component i [kg/hr/component]
N_i is the total number of components of type i
t_{annual} is the annual number of hours the well is in operation [hr/yr]
Y_j is the mass fraction of pollutant j to TOC in the vented gas
0.0011 is the conversion factor from tons to kilograms

County-wide fugitive emissions are calculated using the following equation:

$$E_{fugitive,TOTAL} = E_{fugitive,j} \times N_{well}$$

where:

$E_{fugitive,TOTAL}$ is the total fugitive emission in the county [ton/yr]
$E_{fugitive,j}$ is the fugitive emissions for a single well of pollutant j [ton/yr]
N_{well} is the total number of active wells in the county for a given year

Emissions rates are evaluated at STP.

Number of active wells in a given county for 2008, N_{well}:

Total active wells by county for the full 2008 year are not readily available from the TRC website. However, well distribution data by county is available from the TRC website on a bi-annual (February and September) basis and can be found at: http://www.rrc.state.tx.us/data/wells/wellcount/index.php. ERG used the September 2008 TRC report to get a count of regular producing wells by county.

Emission factor of TOC for a single component, EF_i:

AP-42 emissions factors were used to calculate fugitive emissions from equipment leaks at oil and gas production sites. Emissions factors are referenced from the AP-42 supporting document entitled “Protocol for Equipment Leak Emission Estimations” and summarized in Table 4-22 below.

Table 4-22. AP-42 Emissions Factors for Fugitive Components

Component Type	Emissions Factor (kg-TOC/hr)	
	Gas	Light Oil
Valves	0.0045	0.0025
Pump Seals	0.0024	0.013
Others	0.0088	0.0075
Connectors	0.0002	0.00021
Flanges	0.00039	0.00011
Open-ended Lines	0.002	0.0014

Total number of components, N_i:

The 2008 CENRAP study obtained basin-level data for the total number of components per well from survey data. ERG used this basin level data as a basis for the number of components per well. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-23 for gas wells and Table 4-24 for oil wells. The CENRAP data did not contain information on component counts for “Pump Seals”, or “Others” (equipment such as dump lever arms, polish rod pumps, or hatches). Therefore, an estimate of 2 “Pump Seals” and 10 “Others” were used to gapfill the CENRAP data to complete the inventory (Maldonado, 2010).

Annual number of hours the well is in operation, t_{annual}:

ERG used 8,760 hours per year for the hours the well is in operation.

Mass fraction of pollutant *j* to TOC in the vented gas, Y_j:

The 2008 CENRAP study obtained basin-level data for the fraction of VOC to TOC in the vented gas from survey data. ERG used this basin level data as a basis for the fraction of VOC to TOC in the vented gas. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-23 for gas wells and Table 4-24 for oil wells.

Table 4-23. CENRAP Basin-Level Data for Fugitives at Gas Wells

Basin	Number of Components Per Typical Well						Fraction of VOC in TOC
	Valves	Pump Seals	Others	Connectors	Flanges	Open-Ended Lines	
Anadarko	12	2	10	35	18	6	0.12
East Texas	12	2	10	35	18	6	0.14
Fort Worth	12	2	10	35	18	6	0.15
Permian	19	2	10	43	29	3	0.14
Western Gulf	24	2	10	118	59	3	0.02
Palo Duro[a]	16	2	10	53	28	5	0.11
Marathon Thrust Belt[a]	16	2	10	53	28	5	0.11
Weighted Average	16.54	2.00	10.00	58.53	31.00	4.62	0.11226

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

Table 4-24. CENRAP Basin-Level Data for Fugitives at Oil Wells

Basin	Number of Components Per Typical Well						Fraction of VOC in TOC
	Valves	Pump Seals	Others	Connectors	Flanges	Open-Ended Lines	
Anadarko	20	2	10	90	0	3	0.12
East Texas	20	2	10	90	0	3	0.14
Fort Worth	20	2	10	90	0	3	0.15
Permian	16	2	10	58	12	2	0.14

Table 4-24. CENRAP Basin-Level Data for Fugitives at Oil Wells (Cont.)

Basin	Number of Components Per Typical Well						Fraction of VOC in TOC
	Valves	Pump Seals	Others	Connectors	Flanges	Open-Ended Lines	
Western Gulf	18	2	10	95	25	2	0.02
Palo Duro[a]	19	2	10	85	7	3	0.11
Marathon Thrust Belt[a]	19	2	10	85	7	3	0.11
Weighted Average	18.80	2.00	10.00	84.60	7.40	2.60	0.11226

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

Emissions by county $E_{fugitive,TOTAL}$:

Appendix E presents county-level fugitive emissions corresponding to the number of active oil and gas wells in each county, based on the input variables discussed above.

Example Calculation for Fugitive Emissions (Equipment Leaks):

Using the equations provided above, ERG calculated VOC emissions in Anderson County from equipment leaks at oil wells as follows:

For one well:

$$E_{fugitive,j} = \sum_i EF_i \times N_i \times t_{annual} \times Y_j \times 0.0011$$

Where:

$E_{fugitive,j}$ = VOC emissions from one oil well in Anderson County [tons/well-year]
EF_i = AP-42 emissions factors 0.0025 for valves, 0.013 for pump seals, 0.0075 for others, 0.00021 for connectors, 0.00011 for flanges, and 0.0014 for open ended lines [kg-TOC/hr]
N_i = 18.80 for valves, 2.00 for pump seals, 10.00 for others, 84.60 for connectors, 7.40 for flanges, and 2.60 for open ended lines (number of fugitive areas present in oil wells in Anderson County)
t_{annual} = 8,760 (annual operating hours of oil wells in Anderson County) [hr/yr]
Y_j = 0.11226 (mass fraction of VOC in the TOC vented from the fugitive areas) [ton VOC/ton TOC]

Therefore:

$E_{fugitive,j}$ = 8,760 [hr/yr] x 0.11226 [ton VOC/ton TOC] x 0.0011 [tons/kg] x ((0.0025 * 18.80) + (0.013 * 2.00) + (0.0075 * 10.00) + (0.00021 * 84.60) + (0.00011 * 7.40) + (0.0014 * 2.60) [kg-VOC/well-hr]))

$E_{pneumatic,j}$ = 0.18413 [tons VOC/well-yr]

For all wells in Anderson County:

$$E_{fugitive,TOTAL} = E_{fugitive,j} \times N_{well}$$

Where:

$E_{fugitive,TOTAL}$ = VOC emissions from all oil wells in Anderson County [tons/yr]

$E_{fugitive,j}$ = 0.18413 [tons VOC/well-yr]

N_{well} = 456 (number of oil wells in Anderson County)

Therefore:

$E_{pneumatic,TOTAL}$ = 0.18413 [tons VOC/well-yr] x 456 wells

$E_{pneumatic,TOTAL}$ = 83.97 [tons VOC/yr]

4.10 Heaters and Boilers

The purpose of heaters and boilers at oil and gas production facilities is to provide thermal energy input to certain operations within the production process. They can be used as separator heaters (heater treaters) to provide heat input to separation units, as tank heaters to maintain storage tank temperatures, or as inline heaters to maintain temperature within pipes and connections. Heaters and boilers may also be used in dehydrators; however, these sources are covered under the dehydrator source methodology. Heaters and boilers are typically natural gas-fired external combustors and are a source of NO_x, CO, VOC and PM emissions. SO_2 emissions may also occur if the gas used to fire the heaters contains Hydrogen Sulfide (H_2S) which will be subsequently converted to SO_2 during combustion. County-level emissions from heater sources are estimated for the purpose of this inventory.

Emissions from heaters and boilers were calculated using the methodology from the 2008 CENRAP study (Bar-Ilan, et al., 2008). In this methodology, emissions from a single heater may be calculated using the following equation (excluding SO_2 emissions):

$$E_{heater} = \frac{EF_{heater} \times Q_{heater} \times t_{annual} \times hc}{\left(HV_{local} \times 2000\right)}$$

where:

E_{heater} is the emissions from a given heater [ton/yr]
EF_{heater} is the emission factor for a heater for a given pollutant [lb/MMscf]
Q_{heater} is the heater MMBtu/hr rating [$MMBtu_{rated}$/hr]
HV_{local} is the local natural gas heating value [$MMBtu_{local}$/MMscf]
t_{annual} is the annual hours of operation [hr/yr]
hc is the heater cycling fraction to account for the fraction of operating hours that the heater is firing.
2000 is the conversion factor from pounds to tons of emissions

SO_2 emissions from a single heater may be calculated using the following equation:

$$E_{heater,SO_2} = \frac{1.78 \times f_{H_2S}}{907200} \times \left(\frac{Q_{heater} \times t_{annual} \times hc}{HV_{local}} \times \frac{P}{\left(\frac{R}{MW_{gas}}\right) \times T \times 0.035} \right)$$

where:

$E_{heater,SO2}$ is the SO_2 emissions from a given heater [ton-SO_2/yr]
1.78 is the mass ratio of SO_2 to H_2S
f_{H2S} is the mass fraction of H_2S in the gas
907200 is the conversion factor from grams to tons of emissions
Q_{heater} is the heater MMBtu/hr rating [$MMBtu_{rated}$/hr]
t_{annual} is the annual hours of operation [hr/yr]
hc is the heater cycling fraction to account for the fraction of operating hours that the heater is firing.
HV_{local} is the local natural gas heating value [$MMBtu_{local}$/MMscf]
P is atmospheric pressure [1 atm]
R is the universal gas constant [0.082 L-atm/mol-^{o}K]
MW_{gas} is the molecular weight of the gas [g/mol]
T = 298 (standard temperature) [^{o}K]
0.035 is the conversion factor from cubic feet to liters

The total emissions generated by heaters and boilers from specific county are calculated using the following equation:

$$E_{heater,TOTAL} = E_{heater,i} \times N_{heater} \times \frac{W_{TOTAL,j}}{2000}$$

where:

$E_{heater,TOTAL}$ is the total heater emissions of pollutant i in county j [ton/yr]
$E_{heater,i}$ is the total emissions of pollutant i from a single heater [ton/yr]
$W_{TOTAL,j}$ is the total number of wells in county j
N_{heater} is the typical number of heaters per well in the county
2000 is the conversion factor from pounds to tons of emissions

Total number of wells in a given county for 2008, $W_{TOTAL,j}$:

Total active wells by county for the full 2008 year are not readily available from the TRC website. However, well distribution data by county is available from the TRC website on a bi-annual (February and September) basis and can be found at: http://www.rrc.state.tx.us/data/wells/wellcount/index.php. ERG used the September 2008 TRC report to get a count of regular producing wells by county.

Emission factor for a heater for a given pollutant, EF_{heater}:

ERG used EPA's AP-42 emissions factors when calculating emissions from heaters and boilers at oil and gas production sites. Emissions factors are referenced from Tables 1.4-1 and 1.4-2 of AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources and summarized in Table 4-25 below.

Table 4-25. AP-42 Emissions Factors for Natural Gas Fired Heaters

Pollutant	Emissions Factor (lb/MMscf)
NO_x	100
CO	84
PM_{10}	7.6[a]
VOC	5.5

[a] PM_{10} assumed to be equal to $PM_{2.5}$.

Heater MMBTU/hr rating, Q_{heater}:

The 2008 CENRAP study obtained basin-level data for the heater rating from survey data. ERG used this basin level data as a basis for the heater rating. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-26 for gas wells and Table 4-27 for oil wells.

Local natural gas heating value, HV_{local}:

The 2008 CENRAP study obtained basin-level data for the local heating value from survey data. The same value was used for the gas well heating value and oil well heating value for each basin in the CENRAP report. The gas well value was 1,209 MMBtu/MMscf, and the oil well value was 1,655 MMBtu/MMscf. ERG used this basin level data as a basis for the local heating values.

Annual hours of operation, t_{annual}:

The 2008 CENRAP study obtained basin-level data for the annual heater operating hours from survey data. ERG used this basin level data as a basis for the annual operating hours. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-26 for gas wells and Table 4-27 for oil wells.

Heater cycling fraction, *hc*:

The 2008 CENRAP study used a default value of 1 for heater cycling fraction. ERG also used this as a basis for the heater cycling fraction.

Mass fraction of H_2S, f_{H2S}:

The 2008 CENRAP study obtained basin-level data for the mass fraction of H_2S from survey data. ERG used this basin level data as a basis for the mass fraction of H_2S. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-26 for gas wells and Table 4-27 for oil wells.

Molecular weight of gas, MW_{gas}:

The 2008 CENRAP study obtained basin-level data for the gas molecular weight from survey data. ERG used this basin level data as a basis for the gas molecular weight. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-26 for gas wells and Table 4-27 for oil wells.

Typical number of heater per well, N_{heater}:

The 2008 CENRAP study obtained basin-level data for the average number of heaters per well from survey data. ERG used this basin level data as a basis for the average number of heaters per well. ERG calculated a weighted average based on the number of wells at each basin. This data is summarized in Table 4-26 for gas wells and Table 4-27 for oil wells.

Table 4-26. CENRAP Basin-Level Data for Heaters at Gas Wells

Basin	Heater Operating Parameters					Natural Gas Fuel Parameters	
	Number of heaters in a typical well setup	Heater Firing Rate [MMBtu/hr]	Annual Activity [hr]	Local Heating Value [MMBtu/MMscf]	Heater Cycling	MW_{gas} [g/mol]	H_2S Mass Fraction
Anadarko	0.94	0.92	4,601	1,209	1	21	-
East Texas	0.95	0.64	2,982	1,209	1	19	0.02
Fort Worth	1	0.50	4,380	1,209	1	20	-
Permian	0.54	0.69	4,121	1,209	1	19	0.0001
Western Gulf	1.1	0.46	4,297	1,209	1	19	-
Palo Duro[a]	0.91	0.64	4,076	1,209	1	20	0.005
Marathon Thrust Belt[a]	0.91	0.64	4,076	1,209	1	20	0.005
Weighted Average	0.91	0.64	4,076	1,209	1	20	0.005

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

Table 4-27. CENRAP Basin-Level Data for Heaters at Oil Wells

Basin	Heater Operating Parameters					Natural Gas Fuel Parameters	
	Number of heaters in a typical well setup	Heater Firing Rate [MMBtu/hr]	Annual Activity [hr]	Local Heating Value [MMBtu/MMscf]	Heater Cycling	MW_{gas} [g/mol]	H_2S Mass Fraction
Anadarko	0.94	0.92	4,601	1,655	1	23	-
East Texas	0.95	0.64	2,982	1,655	1	27	1.30
Fort Worth	1	0.50	4,380	1,655	1	25	-
Permian	0.54	0.69	4,121	1,655	1	34	6.50
Western Gulf	1.1	0.46	4,297	1,655	1	25	-
Palo Duro[a]	0.91	0.64	4,076	1,655	1	27	1.56

Table 4-27. CENRAP Basin-Level Data for Heaters at Oil Wells (Cont.)

Basin	Heater Operating Parameters					Natural Gas Fuel Parameters	
	Number of heaters in a typical well setup	Heater Firing Rate [MMBtu/hr]	Annual Activity [hr]	Local Heating Value [MMBtu/MMscf]	Heater Cycling	MW_{gas} [g/mol]	H_2S Mass Fraction
Marathon Thrust Belt[a]	0.91	0.64	4,076	1,655	1	27	1.56
Weighted Average	0.91	0.64	4,076	1,655	1	27	1.56

[a] Data for the Palo Duro and Permian/Marathon Thrust Belt Basins were not included in the CENRAP study. These values are an average of the values from the other basins.

<u>HAP Emissions for Heaters and Boilers</u>:

HAP emissions from heaters and boilers were calculated using VOC and PM speciation data as follows:

$$E_{VOC\text{-}HAP} = E_{VOC} \times (E_{\%VOC\text{-}HAP}/100)$$

where:

$E_{VOC\text{-}HAP}$ = Speciated VOC-HAP emissions [tons/yr]
E_{VOC} = VOC emissions [tons/yr]
$E_{\%VOC\text{-}HAP}$ = % HAP composition of VOC emissions

and

$$E_{PM\text{-}HAP} = E_{PM} \times (E_{\%PM\text{-}HAP}/100)$$

where:

$E_{PM\text{-}HAP}$ = Speciated PM-HAP emissions [tons/yr]
E_{PM} = PM emissions [tons/yr]
$E_{\%PM\text{-}HAP}$ = % HAP composition of PM emissions

Appendix C contains the VOC and PM HAP speciation data.

<u>Emissions by county $E_{heater,TOTAL}$</u>:

Appendix E presents county-level heater emissions corresponding to the number of active oil and gas wells in each county, based on the input variables discussed above.

Example Calculation for Heaters and Boilers:

Using the equations provided above, ERG calculated NO_x and SO_2 emissions in Anderson County from heaters and boilers at oil wells as follows:

For NO_x emissions from one heater:

$$E_{heater} = \frac{EF_{heater} \times Q_{heater} \times t_{annual} \times hc}{\left(HV_{local} \times 2000\right)}$$

Where:

E_{heater} = NO_x emissions from one heater in Anderson County [tons/year]
EF_{heater} = 100 (AP-42 emissions factor for NO_x) [lb/MMscf]
Q_{heater} = 0.64 (heater firing rate) [MMBtu/hr]
HV_{local} = 1,655 (local natural gas heating value) [$MMBTU_{local}$/MMscf])
t_{annual} = 4,076 (annual hours of heater operation) [hr/yr]
hc = 1 (heater cycling fraction to account for the fraction of operating hours that the heater is firing)
2000 is the conversion factor from pounds to tons of emissions

Therefore:

E_{heater} = (100 [lb/MMscf] * 0.64 [MMBtu/hr] * 4,076 [hr/yr] * 1)/(1,655 [MMBtu/MMscf] * 2000 [lb/ton])
E_{heater} = 0.07881 [tons NO_x /heater-yr]

For all wells in Anderson County:

$$E_{heater,TOTAL} = E_{heater,i} \times N_{heater} \times W_{TOTAL,j}$$

Where:

$E_{heater,TOTAL}$ = NO_x emissions from all oil wells in Anderson County [tons/yr]
$E_{heater,j}$ = 0.07881 [tons NO_x /heater-yr]
N_{heater} = 0.91 (average number of heaters per well)
$W_{TOTAL,j}$ = 456 (number of wells in Anderson County)

Therefore:

$E_{heater,TOTAL}$ = 0.07881 [tons NO_x /heater-yr] x 0.91 [heaters/well] x 456 [wells]
$E_{heater,TOTAL}$ = 32.70 [tons NO_x /yr]

For SO_2 emissions from one heater:

$$E_{heater,SO_2} = \frac{1.78 \times f_{H_2S}}{907200} \times \left(\frac{Q_{heater} \times t_{annual} \times hc}{HV_{local}} \times \frac{P}{\left(\frac{R}{MW_{gas}}\right) \times T \times 0.035} \right)$$

Where:

$E_{heater,SO2}$ = SO_2 emissions from one heater [ton-SO_2/yr]
f_{H2S} = 1.56 (mass fraction of H_2S in the gas)
Q_{heater} = 0.64 (heater firing rate) [MMBtu/hr]
HV_{local} = 1,655 (local natural gas heating value) [MMBtu$_{local}$/MMscf])
t_{annual} = 4,076 (annual hours of heater operation) [hr/yr]
hc = 1 (heater cycling fraction to account for the fraction of operating hours that the heater is firing)
P = 1 (standard pressure) [atm]
R = 0.082 (universal gas constant) [L-atm/mol-^{o}K]
T = 298 (standard temperature) [^{o}K]
MW_{gas} = 27 (molecular weight of the gas) [g/mol]

Therefore:

$E_{heater,SO2}$ = ((1.78 * 1.56)/907,200) x (((0.64 [MMbtu/hr] * 4,076 [hr/yr] * 1)/1,655 [MMBtu/MMscf]) x (1/((0.082 [L-atm/mol-^{o}K] /27 [g/mol]) * 298 [^{o}K] * 0.035))
$E_{heater,SO2}$ = 1.5231 x 10^{-4} [tons SO_2/heater-yr]

For all wells in Anderson County:

$$E_{heater,TOTAL} = E_{heater,i} \times N_{heater} \times W_{TOTAL,j}$$

Where:

$E_{heater,TOTAL}$ = SO_2 emissions from all oil wells in Anderson County [tons/yr]
$E_{heater,j}$ = 1.5231 x 10^{-4} [tons SO_2/heater-yr]
N_{heater} = 0.91 (average number of heaters per well)
$W_{TOTAL,j}$ = 456 (number of wells in Anderson County)

Therefore:

$E_{heater,TOTAL}$ = 1.5231 x 10^{-4} [tons SO_2/heater-yr] x 0.91 [heaters/well] x 456 wells
$E_{heater,TOTAL}$ = 0.0632 [tons SO_2/yr]

5.0 RESULTS

Detailed emission estimates developed for this project are found in Appendix D for compressor engines, and in Appendix E for the remainder of the source types. These Appendices contain county-level emissions for source category on an individual pollutant basis. Table 5-1 presents a state-wide summary of criteria pollutant (and total HAP) emissions by source category, Table 5-2 presents a summary of criteria pollutant (and total HAP) emissions for each county, and Table 5-3 presents a summary of state-wide speciated HAP emissions by source type.

As Table 5-1 indicates, natural gas compressor engines account for nearly 70 percent of state-wide NO_x emissions with pumpjack engines accounting for another 20 percent of total NO_x emissions. Oil and gas well heaters account for the remaining 10 percent, with a small contribution from glycol dehydrator boilers. The relative contribution of these sources to state-wide CO emissions are similar, with oil and gas well heaters comprising a slightly higher percentage of emissions at approximately 13 percent.

The majority of PM_{10} and $PM_{2.5}$ emissions are also from combustion sources, but the oil and gas well heaters are the primary source type, contributing nearly 60 percent to state-wide totals. The remainder of PM_{10} and $PM_{2.5}$ emissions come from compressor engines and pumpjack engines, with a small contribution from glycol dehydrator boilers.

The profile is quite different for VOC, where over 70 percent of emissions originate from oil and condensate storage tanks. Condensate tanks in particular comprise over 50 percent of state-wide VOC emissions from oil and gas area sources. The remainder of VOC is emitted from the combustion sources mentioned above, and other minor source types such as well completions and blowdowns, pneumatic devices (which contribute over 10% of the total VOC emissions), and equipment leak fugitives.

The relative profile of the contribution of each source type to state-wide HAP emissions is similar to that of VOC emissions. Oil and condensate storage tanks contribute over 65 percent of the state-wide total HAP emissions, with dehydrators contributing over 15 percent of the state-wide total HAP emissions. The remainder of HAP emissions come from combustion sources and oil and condensate loading racks.

Table 5-1. State-wide Emissions Inventory for 2008 by Source Category

SCC	Source Category Description	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
2310000330	Artificial Lift	23,169.14	46,369.72	154.04	154.04	9.56	440.12	140.49
2310011020	Storage Tanks: Crude Oil						282,420.05	5,060.01
2310011100	Heater Treater	9,267.25	11,032.44	838.47	838.47	21.32	606.78	208.67
2310011201	Tank Truck/Railcar Loading: Crude Oil						26,810.72	479.91
2310011450	Wellhead						116,245.65	
2310011501	Fugitives: Connectors						2,956.39	
2310011502	Fugitives: Flanges						135.46	
2310011503	Fugitives: Open Ended Lines						605.72	
2310011504	Fugitives: Pumps						4,326.59	
2310011505	Fugitives: Valves						7,821.14	
2310011506	Fugitives: Other						12,480.55	
2310020600	Compressor Engines	133.77	255.90	13.58	13.58	0.21	81.40	29.00
2310021010	Storage Tanks: Condensate						864,087.90	17,281.71
2310021030	Tank Truck/Railcar Loading Condensate						7,235.50	144.71
2310021100	Gas Well Heaters	7,564.83	9,005.75	684.44	684.44	0.04	495.32	170.34
2310021101	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines <50 Hp	140.52	209.25	9.72	9.72	0.16	43.38	15.46
2310021102	Natural Gas Fired 2-Cycle Lean Burn Compressor Engines 50 To 499 Hp	2,907.93	13,691.38	352.37	352.37	5.71	2,012.02	716.78
2310021203	Natural Gas Fired 4-Cycle Lean Burn Compressor Engines 500+ Hp	14,746.41	8,801.63	76.95	76.95	15.94	3,817.42	2,337.58
2310021301	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines <50 Hp	93.37	1,175.69	3.86	3.86	0.25	5.61	5.50

Table 5-1. State-wide Emissions Inventory for 2008 by Source Category (Cont.)

SCC	Source Category Description	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
2310021302	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50 To 499hp	38,988.69	86,462.54	226.24	226.24	14.83	1,487.26	1,451.93
2310021400	Gas Well Dehydrators	904.59	293.36				6,344.85	5,255.17
2310021402	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 50-499hp W/ Nscr	767.55	468.45	35.02	35.02	2.05	17.73	17.46
2310021403	Natural Gas Fired 4-Cycle Rich Burn Compressor Engines 500+ Hp W/ Nscr	29,646.80	40,430.00	175.33	175.33	11.26	794.33	775.73
2310021501	Fugitives: Connectors						1,161.52	
2310021502	Fugitives: Flanges						1,199.68	
2310021503	Fugitives: Open Ended Lines						916.82	
2310021504	Fugitives: Pumps						476.31	
2310021505	Fugitives: Valves						7,387.52	
2310021506	Fugitives: Other						8,732.37	
2310021600	Gas Well Venting						8,601.78	
2310021700	Gas Well Completion: All Processes						10,139.56	
2310111700	Oil Well Completion: All Processes						19,425.44	
2310121401	Gas Well Pneumatic Pumps						169,209.86	
	Total:	**128,330.85**	**218,196.11**	**2,570.01**	**2,570.01**	**81.34**	**1,568,522.73**	**34,090.45**

Table 5-2. State-wide Emissions Inventory for 2008 by County

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Anderson	241.28	444.72	5.31	5.31	0.16	2,858.24	52.77
Andrews	1,825.99	3,291.18	49.14	49.14	1.57	31,691.46	444.20
Angelina	161.97	311.11	2.15	2.15	0.08	629.30	25.94
Aransas	165.25	317.00	2.28	2.28	0.09	6,574.04	144.42
Archer	614.91	1,088.88	18.74	18.74	0.58	2,719.03	24.45
Armstrong	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Atascosa	321.56	578.81	8.71	8.71	0.27	2,237.28	31.44
Austin	127.18	237.83	2.42	2.42	0.07	2,040.58	43.74
Bailey	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bandera	0.21	0.37	0.01	0.01	0.00	5.14	0.03
Bastrop	74.21	128.49	2.56	2.56	0.06	1,286.18	16.32
Baylor	26.78	47.39	0.82	0.82	0.03	189.33	1.96
Bee	581.15	1,101.85	9.42	9.42	0.31	4,717.44	125.89
Bell	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bexar	531.99	941.46	16.28	16.28	0.51	2,120.86	7.60
Blanco	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Borden	166.31	300.48	4.40	4.40	0.14	4,107.39	62.92
Bosque	3.45	6.30	0.08	0.08	0.00	17.43	0.34
Bowie	5.13	9.25	0.14	0.14	0.00	148.70	2.69
Brazoria	207.73	199.95	6.59	6.59	0.28	14,003.43	292.15
Brazos	240.26	444.10	5.18	5.18	0.16	3,781.19	74.41
Brewster	0.00	0.00	0.00	0.00	0.00	5.88	0.00
Briscoe	0.00	0.00	0.00	0.00	0.00	12.33	0.01
Brooks	690.71	1,318.85	10.17	10.17	0.35	16,242.00	374.16
Brown	204.73	339.96	8.55	8.55	0.14	1,626.85	6.71
Burleson	366.21	669.08	8.80	8.80	0.28	3,881.39	67.20
Burnet	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Caldwell	676.24	1,197.43	20.61	20.61	0.64	3,452.64	22.69
Calhoun	189.99	360.25	3.07	3.07	0.10	7,473.42	160.35
Callahan	182.61	321.30	5.76	5.76	0.16	983.48	9.65
Cameron	1.68	3.12	0.03	0.03	0.00	10.26	0.20
Camp	30.41	55.01	0.79	0.79	0.03	259.21	4.96
Carson	569.73	1,021.51	15.74	15.74	0.41	1,954.76	34.12
Cass	54.95	98.13	1.55	1.55	0.04	662.46	11.89
Castro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chambers	84.76	94.63	2.75	2.75	0.11	4,424.08	90.13
Cherokee	364.58	682.18	6.78	6.78	0.18	2,911.32	72.93
Childress	1.69	2.99	0.05	0.05	0.00	57.40	0.71
Clay	231.82	409.65	7.14	7.14	0.21	1,476.89	16.60
Cochran	445.16	791.68	13.17	13.17	0.41	6,168.35	67.45
Coke	109.55	200.99	2.54	2.54	0.08	1,010.20	15.88
Coleman	173.73	295.58	6.51	6.51	0.13	1,363.81	9.92
Collin	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Collingsworth	50.04	76.34	2.77	2.77	0.02	742.63	2.58
Colorado	319.38	601.84	5.54	5.54	0.16	4,980.62	115.78
Comal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Comanche	34.22	53.57	1.76	1.76	0.02	438.42	1.97
Concho	72.58	128.12	2.23	2.23	0.06	821.04	9.65
Cooke	495.43	884.64	14.25	14.25	0.45	3,467.02	50.26
Coryell	0.00	0.00	0.00	0.00	0.00	3.13	0.00
Cottle	95.67	180.55	1.63	1.63	0.05	2,376.44	52.30
Crane	1,739.98	3,208.47	38.61	38.61	1.26	17,274.91	291.73
Crockett	2,274.88	4,015.15	68.61	68.61	1.15	28,501.91	414.45
Crosby	85.55	151.51	2.61	2.61	0.08	1,056.14	9.67

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Culberson	72.79	137.98	1.20	1.20	0.04	284.44	8.75
Dallam	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dallas	28.04	6.56	0.21	0.21	0.02	24.60	4.23
Dawson	275.48	492.78	7.84	7.84	0.25	5,344.51	72.02
Deaf Smith	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delta	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Denton	1,763.52	615.91	29.51	29.51	1.14	13,254.59	416.58
Dewitt	676.49	1,300.83	9.00	9.00	0.35	11,617.04	287.72
Dickens	49.70	88.22	1.49	1.49	0.05	1,446.43	20.78
Dimmit	197.89	353.20	5.65	5.65	0.15	2,515.16	31.86
Donley	0.53	0.77	0.03	0.03	0.00	15.82	0.17
Duval	1,111.17	2,101.02	18.70	18.70	0.63	12,897.27	314.00
Eastland	285.26	476.94	11.51	11.51	0.18	3,654.84	39.72
Ector	1,798.24	3,277.22	44.40	44.40	1.47	26,211.12	388.97
Edwards	270.78	492.35	6.60	6.60	0.13	1,377.01	25.49
El Paso	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ellis	51.17	13.49	0.47	0.47	0.04	52.43	7.56
Erath	161.14	295.43	3.68	3.68	0.07	1,556.95	32.84
Falls	4.01	7.09	0.12	0.12	0.00	21.49	0.09
Fannin	0.00	0.00	0.00	0.00	0.00	11.86	0.00
Fayette	356.62	659.40	7.64	7.64	0.23	5,607.61	115.67
Fisher	107.82	193.50	2.99	2.99	0.09	1,365.54	16.44
Floyd	0.42	0.75	0.01	0.01	0.00	2.97	0.03
Foard	27.94	43.90	1.42	1.42	0.01	414.38	2.57
Fort Bend	169.68	171.80	5.51	5.51	0.22	8,072.59	166.58
Franklin	69.40	127.99	1.52	1.52	0.05	1,389.52	28.31
Freestone	3,821.60	7,289.51	56.95	56.95	1.93	9,858.72	475.09

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Frio	139.12	246.28	4.21	4.21	0.12	1,393.74	14.40
Gaines	1,165.52	2,133.47	27.65	27.65	0.92	27,788.32	460.84
Galveston	86.46	76.28	2.61	2.61	0.12	17,475.45	358.12
Garza	445.72	790.41	13.45	13.45	0.42	6,133.80	63.01
Gillespie	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Glasscock	416.67	761.54	10.00	10.00	0.32	5,431.20	84.49
Goliad	731.21	1,386.08	11.85	11.85	0.37	7,851.72	199.63
Gonzales	51.40	92.76	1.37	1.37	0.04	578.12	8.62
Gray	825.55	1,440.69	27.11	27.11	0.64	4,163.88	45.84
Grayson	201.98	365.62	5.22	5.22	0.16	1,707.03	31.65
Gregg	1,423.90	2,592.32	34.92	34.92	1.00	10,980.44	227.68
Grimes	334.10	638.29	4.87	4.87	0.17	1,264.12	50.60
Guadalupe	402.11	711.73	12.29	12.29	0.38	2,576.45	22.66
Hale	62.99	114.67	1.57	1.57	0.05	2,698.37	46.20
Hall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hamilton	3.12	5.33	0.11	0.11	0.00	36.47	0.47
Hansford	377.68	676.20	10.32	10.32	0.17	2,601.06	43.25
Hardeman	52.13	92.68	1.54	1.54	0.05	1,230.36	19.89
Hardin	258.68	348.83	7.85	7.85	0.30	22,648.65	447.94
Harris	176.00	181.67	5.65	5.65	0.23	8,801.29	184.44
Harrison	1,879.59	3,514.48	35.19	35.19	0.93	25,383.90	583.58
Hartley	39.06	70.27	1.04	1.04	0.02	399.51	6.56
Haskell	53.83	95.30	1.64	1.64	0.05	443.81	5.44
Hays	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hemphill	2,092.63	3,936.72	37.08	37.08	1.03	32,774.76	754.74
Henderson	453.75	854.13	7.99	7.99	0.24	2,535.12	73.92
Hidalgo	3,264.69	6,276.64	43.49	43.49	1.68	56,554.95	1,407.72

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Hill	308.20	597.97	3.53	3.53	0.16	233.61	34.41
Hockley	1,004.10	1,795.93	28.58	28.58	0.91	22,011.88	308.12
Hood	926.80	1,777.59	12.89	12.89	0.47	9,914.41	269.97
Hopkins	20.84	37.79	0.53	0.53	0.02	298.78	5.06
Houston	164.62	308.00	3.11	3.11	0.10	1,587.91	35.84
Howard	803.87	1,436.74	23.00	23.00	0.73	9,904.95	107.63
Hudspeth	0.12	0.17	0.01	0.01	0.00	3.29	0.03
Hunt	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hutchinson	903.43	1,601.32	27.09	27.09	0.72	4,039.66	49.29
Irion	531.51	961.89	13.77	13.77	0.40	5,877.27	82.51
Jack	646.65	1,121.02	21.80	21.80	0.42	6,701.91	92.20
Jackson	303.15	569.09	5.55	5.55	0.17	9,879.64	204.59
Jasper	205.58	394.00	2.87	2.87	0.11	6,405.78	143.58
Jeff Davis	0.00	0.00	0.00	0.00	0.00	1.29	0.03
Jefferson	287.19	182.64	8.05	8.05	0.46	55,659.21	1,163.27
Jim Hogg	266.50	500.41	4.83	4.83	0.14	4,021.10	92.33
Jim Wells	127.37	226.90	3.61	3.61	0.06	1,576.61	26.20
Johnson	4,495.48	1,157.96	43.01	43.01	3.19	5,209.18	684.81
Jones	167.32	296.69	5.05	5.05	0.16	1,277.91	14.79
Karnes	171.32	323.25	2.95	2.95	0.10	3,454.12	76.12
Kaufman	4.50	7.85	0.14	0.14	0.00	62.82	1.05
Kendall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kenedy	665.44	1,286.34	8.13	8.13	0.35	4,087.71	143.43
Kent	203.51	375.70	4.48	4.48	0.16	4,304.19	73.92
Kerr	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kimble	2.94	4.50	0.16	0.16	0.00	41.29	0.17
King	112.59	198.82	3.47	3.47	0.10	2,010.47	35.20

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Kinney	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kleberg	494.21	948.96	6.71	6.71	0.25	8,845.84	217.77
Knox	46.18	81.72	1.41	1.41	0.04	354.81	4.00
La Salle	259.22	470.95	6.38	6.38	0.13	4,078.69	76.37
Lamar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lamb	15.10	27.13	0.42	0.42	0.01	686.85	11.01
Lampasas	0.16	0.20	0.01	0.01	0.00	4.24	0.00
Lavaca	924.67	1,764.89	13.68	13.68	0.47	12,277.67	311.64
Lee	307.30	564.26	7.08	7.08	0.23	2,650.76	49.84
Leon	1,079.72	2,070.29	15.01	15.01	0.58	5,733.49	197.49
Liberty	331.40	341.24	9.92	9.92	0.45	27,316.75	570.30
Limestone	1,393.87	2,655.14	21.17	21.17	0.71	4,377.56	180.91
Lipscomb	1,125.34	2,104.13	21.36	21.36	0.58	17,104.94	381.52
Live Oak	378.16	709.70	6.91	6.91	0.20	6,807.99	149.58
Llano	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Loving	1,567.71	3,023.10	20.15	20.15	0.89	6,348.57	251.69
Lubbock	89.19	158.04	2.71	2.71	0.08	1,825.32	23.15
Lynn	18.52	33.00	0.54	0.54	0.02	350.40	4.52
Madison	117.26	216.26	2.56	2.56	0.07	1,290.52	26.07
Marion	96.78	174.38	2.56	2.56	0.06	1,407.02	25.69
Martin	596.73	1,088.02	14.69	14.69	0.49	10,928.66	168.72
Mason	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Matagorda	609.79	1,168.96	8.47	8.47	0.32	19,098.24	428.64
Maverick	182.47	323.89	5.42	5.42	0.15	3,715.58	42.08
McCulloch	14.65	25.47	0.50	0.50	0.01	109.65	1.15
McLennan	8.65	15.30	0.26	0.26	0.01	27.43	0.12
McMullen	493.90	900.42	11.92	11.92	0.29	6,027.42	110.63

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Medina	275.72	487.25	8.50	8.50	0.26	1,235.77	4.54
Menard	27.00	47.52	0.85	0.85	0.02	266.84	2.69
Midland	1,610.04	2,951.97	37.75	37.75	1.27	20,938.23	333.93
Milam	218.91	387.83	6.65	6.65	0.21	1,216.87	9.32
Mills	0.36	0.51	0.02	0.02	0.00	6.38	0.02
Mitchell	502.49	890.13	15.28	15.28	0.48	6,645.63	65.00
Montague	551.48	987.06	15.59	15.59	0.49	3,448.92	48.39
Montgomery	73.56	81.80	2.86	2.86	0.08	2,890.56	54.67
Moore	744.02	1,343.19	19.29	19.29	0.40	3,502.87	63.64
Morris	0.21	0.37	0.01	0.01	0.00	2.01	0.03
Motley	3.80	6.72	0.12	0.12	0.00	52.75	0.49
Nacogdoches	1,527.76	2,897.04	24.29	24.29	0.77	12,723.39	353.60
Navarro	170.24	301.61	5.16	5.16	0.16	1,444.51	18.73
Newton	78.50	145.69	1.63	1.63	0.05	1,601.94	31.72
Nolan	133.50	240.21	3.63	3.63	0.11	1,931.63	25.88
Nueces	605.47	1,127.23	11.99	11.99	0.31	15,740.17	332.51
Ochiltree	561.88	1,020.35	13.94	13.94	0.31	5,760.68	108.67
Oldham	5.68	10.02	0.17	0.17	0.00	247.24	3.74
Orange	67.79	71.25	2.06	2.06	0.09	8,467.82	172.90
Palo Pinto	455.72	785.82	15.70	15.70	0.21	7,033.45	105.26
Panola	3,784.21	7,052.88	73.18	73.18	1.82	50,362.96	1,170.88
Parker	1,225.52	407.43	19.49	19.49	0.80	9,840.76	290.06
Parmer	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pecos	4,534.56	8,670.50	66.30	66.30	2.63	21,760.89	703.44
Polk	415.68	797.76	5.69	5.69	0.22	29,650.93	625.12
Potter	350.79	632.33	9.25	9.25	0.21	1,799.21	27.27
Presidio	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Rains	59.61	115.43	0.71	0.71	0.03	38.47	6.62
Randall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reagan	1,209.82	2,204.56	29.89	29.89	0.99	11,808.61	158.58
Real	1.91	3.34	0.06	0.06	0.00	16.74	0.15
Red River	9.57	16.96	0.29	0.29	0.01	159.73	2.26
Reeves	575.50	1,077.94	10.88	10.88	0.36	3,146.28	72.34
Refugio	652.55	1,218.19	12.72	12.72	0.40	9,671.07	197.77
Roberts	881.18	1,659.43	15.47	15.47	0.45	15,296.54	346.65
Robertson	3,591.03	6,960.37	41.87	41.87	1.90	4,202.14	427.68
Rockwall	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Runnels	145.66	262.06	3.96	3.96	0.12	1,177.54	15.82
Rusk	2,394.04	4,447.78	48.27	48.27	1.34	26,428.99	597.16
Sabine	2.04	3.67	0.06	0.06	0.00	19.20	0.14
San Augustine	159.66	309.99	1.77	1.77	0.09	452.69	23.22
San Jacinto	182.43	350.28	2.47	2.47	0.09	6,462.64	144.35
San Patricio	303.08	570.53	5.36	5.36	0.16	12,721.07	267.75
San Saba	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Schleicher	297.16	521.39	9.30	9.30	0.15	3,975.13	56.43
Scurry	920.14	1,696.28	20.52	20.52	0.72	16,745.60	282.63
Shackelford	446.66	787.83	13.87	13.87	0.39	2,584.60	27.41
Shelby	788.21	1,506.84	11.24	11.24	0.40	4,681.48	153.59
Sherman	382.36	689.34	9.93	9.93	0.17	2,226.58	38.78
Smith	600.16	1,117.21	11.83	11.83	0.32	6,759.09	157.15
Somervell	69.05	132.73	0.93	0.93	0.04	261.32	10.71
Starr	1,801.98	3,435.69	27.08	27.08	0.92	39,905.70	922.75
Stephens	548.00	962.55	17.22	17.22	0.36	6,028.28	86.04
Sterling	507.62	898.57	15.24	15.24	0.35	5,045.87	54.84

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Stonewall	125.21	222.61	3.72	3.72	0.12	1,647.78	17.01
Sutton	1,536.07	2,640.40	53.45	53.45	0.57	14,703.05	158.36
Swisher	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tarrant	4,070.91	1,055.42	39.54	39.54	2.88	4,929.92	620.02
Taylor	92.16	163.25	2.80	2.80	0.09	693.08	8.42
Terrell	890.56	1,697.22	13.46	13.46	0.45	4,554.08	153.52
Terry	217.93	388.12	6.39	6.39	0.20	5,118.11	70.81
Throckmorton	221.50	393.95	6.55	6.55	0.20	1,242.06	15.21
Titus	42.19	74.68	1.29	1.29	0.04	506.68	8.03
Tom Green	170.07	304.64	4.76	4.76	0.14	1,945.37	23.40
Travis	3.37	5.97	0.10	0.10	0.00	14.43	0.07
Trinity	10.94	19.88	0.27	0.27	0.01	193.38	3.42
Tyler	463.76	896.18	5.69	5.69	0.25	57,953.39	1,201.05
Upshur	604.48	1,126.42	11.73	11.73	0.30	10,582.53	238.20
Upton	1,602.98	2,998.03	30.90	30.90	1.09	32,833.54	647.89
Uvalde	0.20	0.26	0.02	0.02	0.00	4.37	0.01
Val Verde	210.53	394.38	3.90	3.90	0.10	620.76	21.64
Van Zandt	193.81	352.82	4.81	4.81	0.15	1,204.59	23.27
Victoria	287.47	535.68	5.67	5.67	0.16	3,296.01	69.83
Walker	13.49	24.74	0.31	0.31	0.01	85.26	1.73
Waller	88.01	106.67	2.83	2.83	0.11	2,859.24	56.46
Ward	1,288.64	2,381.97	28.00	28.00	0.94	9,588.88	230.25
Washington	256.76	485.36	4.31	4.31	0.14	2,513.65	64.54
Webb	3,123.82	5,806.41	62.66	62.66	1.48	28,275.41	664.71
Wharton	692.11	1,309.84	11.43	11.43	0.37	15,986.48	354.54
Wheeler	2,223.92	4,231.74	34.40	34.40	1.15	40,674.02	955.94
Wichita	1,185.96	2,099.33	36.23	36.23	1.13	5,040.04	46.60

Table 5-2. State-wide Emissions Inventory for 2008 by County (Cont.)

County	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	Total HAP (tons/yr)
Wilbarger	174.53	308.95	5.33	5.33	0.17	1,147.90	13.03
Willacy	353.53	681.05	4.59	4.59	0.19	8,274.58	193.92
Williamson	9.07	16.05	0.28	0.28	0.01	53.29	0.33
Wilson	129.98	230.01	3.98	3.98	0.12	757.55	6.10
Winkler	917.14	1,698.44	19.52	19.52	0.63	7,815.47	141.18
Wise	2,749.59	5,099.17	55.75	55.75	1.35	24,225.59	597.53
Wood	239.16	438.82	5.52	5.52	0.18	4,200.35	82.03
Yoakum	1,074.18	1,960.14	26.21	26.21	0.88	25,649.46	414.59
Young	556.32	978.60	17.57	17.57	0.50	3,394.26	35.11
Zapata	4,438.24	8,472.07	65.54	65.54	2.24	13,384.86	594.31
Zavala	64.75	114.70	1.94	1.94	0.05	1,016.76	14.24
Total:	**128,330.85**	**218,196.11**	**2,570.01**	**2,570.01**	**81.34**	**1,568,522.73**	**34,090.45**

Table 5-3. State-wide Speciated HAP Emissions by Source Category

Hazardous Air Pollutant	Source Category						
	Dehydrators	Pump Jacks	Oil and Gas Heaters	Tank Truck/Railcar Loading	Natural Gas Compressor Engines	Storage Tanks	Statewide Total
1,1,2,2-Tetrachloroethane		0.10			3.23		3.33
1,1,2-Trichloroethane		0.06			2.19		2.25
1,3-Butadiene		2.59			59.71		62.30
1,3-Dichloropropene		0.05			1.82		1.87
1,4-Dichlorobenzene		4.69	0.24		38.67		43.60
2,2,4-Trimethylpentane					7.95		7.95
2-Methylnaphthalene		0.09	0.005		2.91		3.01
3-Methylcholanthrene		0.01	0.0004		0.20		0.20
7,12-Dimethylbenz[a]Anthracene		0.06	0.003		1.74		1.81
Acenaphthene		0.36	0.001		0.23		0.59
Acenaphthylene		0.36	0.001		0.65		1.01
Acetaldehyde		10.91	1.78		481.46		494.14
Acrolein		10.28			366.67		376.95
Anthracene		0.48	0.00		0.37		0.86
Benz[a]Anthracene		0.36	0.00		0.28		0.64
Benzene	1,477.65	6.18	0.42	129.92	136.05	5,794.48	7,544.70
Benzo(g,h,i)Fluoranthene		0.24			0.00		0.24
Benzo[a]Pyrene		0.24	0.001		0.07		0.31
Benzo[b]Fluoranthene		0.36	0.001		0.12		0.48
Benzo[e]Pyrene					0.04		0.04
Benzo[g,h,i,]Perylene			0.001		0.11		0.11
Benzo[k]Fluoranthene		0.36	0.001		0.28		0.64
Biphenyl					6.74		6.74
Carbon Tetrachloride		0.07			2.53		2.60
Chlorobenzene		0.05			1.96		2.01
Chloroform		0.05			1.96		2.02
Chrysene		0.36	0.001		0.17		0.53
Dibenzo[a,h]Anthracene		0.24	0.001		0.19		0.43
Ethyl Benzene	88.89	0.10		54.19	3.18	1,003.02	1,149.37

Table 5-3. State-wide Speciated HAP Emissions by Source Category (Cont.)

Hazardous Air Pollutant	Source Category						
	Dehydrators	Pump Jacks	Oil and Gas Heaters	Tank Truck/Railcar Loading	Natural Gas Compressor Engines	Storage Tanks	Statewide Total
Ethylene Dibromide		0.08			3.05		3.14
Fluoranthene		0.60	0.002		0.28		0.88
Fluorene		0.56	0.002		0.72		1.29
Formaldehyde		80.13	15.03		3,263.20		3,358.36
Hexane			360.69		781.76		1,142.45
Indeno[1,2,3-c,d]Pyrene		0.36	0.001		0.28		0.64
Methanol		11.96			80.80		92.76
Methylene Chloride		0.16			3.82		3.98
m-Xylene		0.04			0.44		0.49
Naphthalene		0.38	0.12		9.87		10.37
o-Xylene		0.04			0.83		0.87
Phenanthrene		3.50	0.01		2.02		5.54
Phenol					0.76		0.76
Pyrene		1.00	0.004		0.42		1.42
Styrene		0.05			1.67		1.72
Toluene	786.98	2.18	0.68	208.89	56.08	9,756.68	10,811.49
Vinyl Chloride		0.03			1.03		1.06
Xylenes (Mixture of o, m, and p Isomers)	2,901.66	0.76		231.62	20.92	5,787.54	8,942.50
Statewide Total	**5,255.17**	**140.49**	**379.00**	**624.62**	**5,349.44**	**22,341.72**	**34,090.45**

6.0 FORMATTED TexAER FILES

Once the emissions inventory was completed, the data was prepared for electronic submittal to the Texas Air Emissions Repository (TexAER) using the National Emissions Inventory (NEI) Input Format (NIF) 3.0. Area source text-formatted input files were prepared for all onshore oil and gas area source categories for a 2008 base year. The NIF 3.0 files were created using information provided by TCEQ regarding the correct format and valid code listings for submittal to TexAER. Prior to submittal to TCEQ, the NIF 3.0 files were pre-processed using EPA's NIF Basic Format and Content Checker to check for errors and inconsistencies. Additionally, ERG performed a test upload to TexAER to ensure the files were complete and accurate and in a format consistent with the TexAER area source file data requirements. The formatted TexAER files are included as Appendix F.

7.0 CONCLUSIONS AND RECOMMENDATIONS

This study presents a comprehensive, statewide 2008 emissions inventory for Texas for onshore, upstream oil and gas production area sources. Data used to prepare the emissions inventory were obtained from a variety of sources, including existing databases (such as the Texas Railroad Commission (TRC) oil and gas production data), point source emissions inventory reports submitted to TCEQ (for dehydrators), vendor data (for compression engines and pumpjack engines), and published emission factor and activity data from the Houston Advanced Research Center (HARC), the Central Regional Air Planning Association (CENRAP), and the U.S. Environmental Protection Agency (EPA).

Further improvements to this inventory could be made through collection of County-level activity data through use of the survey instrument developed as described in Section 3.0. Such a survey will help quantify the specific number, size, type, and location of the various equipment types used at upstream oil and gas production sites in Texas.

While characterization of emissions from all of the source types would benefit from detailed survey data, there are a few categories where minimal Texas-specific data was available. Specifically, this inventory was based on default profiles for several source categories that could be improved through implementation of the survey as follows:

- Well Completions and Well Blowdowns - survey data is needed to determine the volumes of gas released during these operations, the composition of the gas released, and the extent that these operations are controlled;
- Pneumatic Devices - survey data is needed to determine the number of devices used at each upstream oil and gas production site, the bleed rates for each equipment type, and the composition of the natural gas released from these sources;
- Fugitive Emissions (Equipment Leaks) - this could be a significant source category and there is some uncertainty as to the current estimate of the number and types of fugitive emission soruces (valves, flanges, etc.). As with well completions and well blowdowns, gas composition data is needed to be able to speciate the emissions from this source category; and
- Heaters and Boilers - survey data is needed to quantify the number and size of these small combustion units located at upstream oil and gas production sites.

Also, HAP emissions could be estimated for several source categories not currently included in the HAP inventory if HAP speciation data could be obtained for the chemical composition of the natural gas emitted during various processes. In particular, this data would be used to estimate HAP emissions from well completions, well blowdowns, pneumatic devices, and equipment leaks.

It is likely the current inventory may be overestimating emissions to some degree from some sources due to the lack of information on control device use. In particular, this data would be useful for well completions (flaring and "green completion" techniques), oil and condensate storage tanks and loading racks (vapor recovery units and flares), and engines (SCR and NSCR). Again, information submitted by the operators would help account for emission control measures providing more accurate emission estimates.

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Appendix A – Task 2 Memorandum

TECHNICAL MEMORANDUM

Date: April 26, 2010

To: Martha Maldonado
Project Representative
Texas Commission on Environmental Quality (TCEQ)

From: Richard Billings, Eastern Research Group (ERG)
Daryl Hudson (ERG)
Mike Pring (ERG)
Jason Renzaglia (ERG)
Brandon Smith (ERG)
Stephen Treimel (ERG)

Re: Oil and Gas Sources Inventory - Final Technical Memorandum for Task 2
TCEQ Contract No. 582-7-84003, Work Order No. 582-7-84003-FY10-26

1.0 Introduction

The purpose of this Work Order is to develop a 2008 base year air emissions inventory from upstream onshore oil and gas production sites for select counties in Texas. The inventory will address area source criteria pollutant emissions of volatile organic compounds (VOC), nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and sulfur dioxide (SO_2); and certain toxic pollutant emissions such as formaldehyde, benzene, toluene, ethylbenzene, and xylene. In addition to compiling the emissions inventory, other goals of this Work Order are to identify the emission source types operating at oil and gas production sites, identify the best emissions determination methodology for each emission source type, and develop a methodology for estimating emissions from oil and gas production sites based on the oil and gas produced at the county level.

This Work Order builds on two previous studies ERG conducted for TCEQ to estimate emissions from oil and gas exploration and production activities. The first, implemented in 2007, focused on compiling a state-wide emissions inventory (including both onshore and offshore sources) for oil and gas exploration and production for a 2005 base year (ERG, 2007). The second study, conducted in 2009 for a 2008 base year, focused only on emissions from onshore oil and gas well drilling rig engines (ERG, 2009). Both of these studies included emission estimates for every county in Texas. In contrast, this current study will only address onshore area sources (those not included in the Texas point source inventory), and excludes the 23 counties in the Barnett Shale area (Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Somervell, Stephens, Tarrant, and Wise). TCEQ is currently developing an emissions inventory for oil and gas sources in the Barnett Shale, and offshore oil and gas platforms are currently under evaluation as part of TCEQ Work Order No. 582-07-84003-FY10-25.

The project is divided into four primary technical work tasks:

- Identification and review of existing studies pertaining to estimating emissions from oil and gas production sites and recommendation of an emission estimation approach for each identified source type;
- Collection of activity and emissions data through an industry survey and, as available, obtain data from existing studies and databases;
- Development of a methodology to estimate county-level emissions from each identified source type; and
- Performance of emissions estimation calculations, including documentation of data, procedures, and results in a final project report. The final emissions inventory will be compiled into National Emissions Inventory Input Format (NIF) 3.0 text files for import into Texas Air Emissions Repository (TexAER).

The purpose of this memo is to identify and summarize emission estimation methodologies available for oil and gas production sites as determined through a technical review and evaluation of recent studies of emission sources at oil and gas production sites. In the project Work Plan, this work is referred to as Task 2. The existing studies reviewed and a summary of the available and recommended emission estimation approaches for each source type are presented in this memo, including summaries of the data required to implement the preferred approach and ERG's recommendations how best to obtain the needed data. In addition, any data gaps identified that impact the ability to develop a 2008 inventory estimate for a category are described and possible methods for addressing the data gaps (through the use of existing or default data) are presented.

This discussion begins by presenting the list of oil and gas source types that are the focus of this project in Section 2.0, Identification of Source Categories. A specific list of source types was contained in the Work Order and these source types were the focus of the Task 2 analysis, although this analysis was not limited to only those source types. As other additional source types were identified in the course of reviewing the existing studies, they are also included in this analysis. In Section 3.0, the specific oil and gas emission source types addressed in the project are presented, along with a review of any relevant existing studies, and a recommended emission estimation approach. Section 4.0 includes the references used in preparation of this memorandum. Appendix A contains a list of acronyms and abbreviations used in the text of this document. Terms are also defined in the text the first time they are used.

2.0 Identification of Source Categories

The majority of the oil and gas production source categories analyzed in this project were also included in the previous TCEQ Oil and Gas study (ERG, 2007). Other oil and gas emissions sources were specified by TCEQ in the work order.

For the purposes of this project and this memorandum, the following oil and gas source types have been addressed:

- Well Completions
- Well Blowdowns
- Wellheads
- Pneumatic Devices
- Fugitive Emissions (Equipment Leaks)
- Artificial Lift (Pumpjack) Engines
- Heaters and Boilers
- Dehydrators
- Storage Tanks
- Oil and Condensate Loading Racks
- Compressor Engines
- Turbines

These types of sources are considered "upstream" sources, which include activities associated with searching for potential oil and gas fields, drilling of exploratory wells, and subsequently development and operating the wells that recover and bring the natural gas and/or oil to the surface. The majority of upstream sources are area sources and are not currently accounted for in the point sources inventory.

"Midstream" and "downstream" sources are associated with those operations that subsequently store, process, refine, market, and transport oil and gas products such as crude oil, natural gas, gasoline, and natural gas liquids. These types of sources are typically included in the point source emissions inventory, and consist of gas processing plants, pipeline compressor stations, and oil refineries. Point sources are not included in this inventory effort.

Table 1 provides a summary of the general source category types listed above, the specific operations or processes that generate air emissions, and identification of the pollutants associated with each source. Table 2 identifies the specific emission processes, and the list of available Source Classification Codes (SCCs) for association with each source type. The SCC list is based on a list of available SCC’s for oil and gas sources as provided to ERG by TCEQ.

The final list of SCC's used to compile the emissions inventory into the NIF 3.0 text files will be provided in the emissions inventory report. The structure of the SCC scheme for many of the source types included in this study allows for aggregation of emissions under one SCC, or the use of multiple SCC's if sufficient detailed data is obtained to disaggregate emissions into smaller sub-categories. For example, SCC 2310011500 may be used for "FUGITIVES: ALL PROCESSES" from oil production, or there are 6 separate SCC's that may be used to disaggregate fugitive emissions into sub-categories of "connectors", "flanges", "valves", "open ended lines", "pumps", and "other".

Table 1. Identification of Source Categories Addressed in the Texas Oil and Gas Emission Inventory

Oil & Gas Source Type	Specific Emission Sources	Potential Pollutants
Well Completions	Emissions from venting/flaring from the well completion phase	CO, NO_X, VOC
Well Blowdowns	Emissions from venting/flaring from well blowdowns	CO, NO_X, VOC
Wellheads	Emissions from wellhead assemblies and rod pumps	VOC
Pneumatic Devices	Fugitive emissions from pneumatic devices used during well exploration and production	VOC
Fugitive Emissions (Equipment Leaks)	Fugitive emissions from pumps and piping components	VOC
Artificial Lift Engines (Pumpjack Engines)	Combustion emissions from artificial lift engines associated with oil production	SO_2, NO_x, VOC, PM, CO
Heaters and Boilers	Emissions from natural gas-fired heaters and boilers	SO_2, NO_x, VOC, PM, CO
Dehydrators	Emissions from glycol dehydrator still vents and reboilers	VOC, Benzene, Toluene, Ethylbenzene, Xylene
Storage Tanks	Working, breathing, and flashing losses from oil and condensate storage tanks	VOC
Oil and Condensate Loading Racks	Fugitive emissions from truck and/or railcar loading	VOC
Compressor Engines	Combustion emissions from compressor engines associated with oil and gas production	SO_2, NO_x, VOC, PM, CO, Formaldehyde
Turbines	Combustion emissions from turbines associated with oil and gas production	SO_2, NO_x, VOC, PM, CO

Table 2. Assignment of SCCs to Texas Oil and Gas Sources[a]

SCC	Tier Description	Short Description
2270010010	OTHER OIL FIELD EQUIPMENT	DIESEL: INDUSTRIAL EQUIPMENT: OTHER OIL FIELD EQUIPMENT (DRILLING RIGS)
2310000000	TOTAL: ALL PROCESSES	OIL & GAS EXPLORATION AND PRODUCTION ALL PROCESSES
2310000330	ARTIFICIAL LIFT	OIL AND GAS EXPLORATION AND PRODUCTION ARTIFICIAL LIFT
2310001000	TOTAL: ALL PROCESSES	ON SHORE OIL & GAS EXPLORATION & PRODUCTION ALL PROCESSES
2310010000	TOTAL: ALL PROCESSES	CRUDE OIL PRODUCTION ALL PROCESSES
2310010100	OIL WELL HEATERS	OIL PRODUCTION WELL HEATERS
2310010200	TANKS - FLASHING & STANDING/ WORKING/ BREATHING	OIL PRODUCTION TANKS INCLUDING FLASHING
2310010300	PNEUMATIC DEVICES	OIL PRODUCTION PNEUMATIC DEVICES
2310010700	OIL WELL FUGITIVES	OIL AND GAS EXPLORATION AND PRODUCTION OIL WELL FUGITIVES
2310010800	OIL WELL TRUCK LOADING	OIL AND GAS EXPLORATION AND PRODUCTION OIL WELL TRUCK LOADING
2310011000	TOTAL: ALL PROCESSES	ON SHORE CRUDE OIL PRODUCTION ALL PROCESSES
2310011020	STORAGE TANKS: CRUDE OIL	ON SHORE OIL PRODUCTION CRUDE TANKS
2310011100	HEATER TREATER	ON SHORE OIL PRODUCTION HEATER TREATER
2310011201	TANK TRUCK/RAILCAR LOADING: CRUDE OIL	ON SHORE OIL PRODUCTION TRUCK/RAIL LOADING OF CRUDE
2310011450	WELLHEAD	ON SHORE OIL PRODUCTION WELLHEAD
2310011500	FUGITIVES: ALL PROCESSES	ON SHORE OIL PRODUCTION FUGITIVES ALL PROCESSES
2310011501	FUGITIVES: CONNECTORS	ON SHORE OIL PRODUCTION FUGITIVES CONNECTORS
2310011502	FUGITIVES: FLANGES	ON SHORE OIL PRODUCTION FUGITIVES FLANGES
2310011503	FUGITIVES: OPEN ENDED LINES	ON SHORE OIL PRODUCTION FUGITIVES OPEN ENDED LINES
2310011504	FUGITIVES: PUMPS	ON SHORE OIL PRODUCTION FUGITIVES PUMPS
2310011505	FUGITIVES: VALVES	ON SHORE OIL PRODUCTION FUGITIVES VALVES
2310011506	FUGITIVES: OTHER	ON SHORE OIL PRODUCTION FUGITIVES OTHER
2310020000	TOTAL: ALL PROCESSES	NATURAL GAS EXPLORATION AND PRODUCTION: ALL PROCESSES
2310020309	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES: ALL	ON-SHORE GAS PRODUCTION 4CYCLE RICH BURN COMPRESSORS
2310020600	COMPRESSOR ENGINES	GAS PRODUCTION COMPRESSOR ENGINES (FOR WRAP USE)
2310020700	GAS WELL FUGITIVES	NATURAL GAS PRODUCTION GAS WELL FUGITIVES
2310020800	GAS WELL TRUCK LOADING	NATURAL GAS PRODUCTION GAS WELL TRUCK LOADING

SCC	Tier Description	Short Description
2310021000	TOTAL: ALL PROCESSES	ON SHORE GAS PRODUCTION: ALL PROCESSES
2310021010	STORAGE TANKS: CONDENSATE	ON-SHORE GAS PRODUCTION: STORAGE TANKS: CONDENSATE
2310021030	TANK TRUCK/RAILCAR LOADING CONDENSATE	ON SHORE GAS PRODUCTION TRUCK AND RAIL LOADING OF CONDENSATE
2310021100	GAS WELL HEATERS	ON-SHORE GAS PRODUCTION HEATERS
2310021101	NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES <50 HP	ON-SHORE GAS PRODUCTION: NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES <50 HP
2310021102	NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES 50 TO 499 HP	ON-SHORE GAS PRODUCTION: NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES 50 TO 499 HP
2310021103	NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES 500+ HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES 500+ HP
2310021109	NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES: ALL	ON-SHORE GAS PRODUCTION: NATURAL GAS FIRED 2-CYCLE LEAN BURN COMPRESSOR ENGINES: ALL
2310021201	NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES <50 HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES <50 HP
2310021202	NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES 50-499HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES 50 HP - 499 HP
2310021203	NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES 500+ HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES 500+ HP
2310021209	NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE LEAN BURN COMPRESSOR ENGINES
2310021300	GAS WELL PNEUMATIC DEVICES	ON-SHORE GAS PRODUCTION PNEUMATIC DEVICES
2310021301	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES <50 HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES <50 HP
2310021302	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES 50 TO 499HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES 50 TO 499 HP
2310021303	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES 500+ HP	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES 500+ HP
2310021400	GAS WELL DEHYDRATORS	ON-SHORE GAS PRODUCTION DEHYDRATORS
2310021401	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES <50 HP W/ NSCR	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENG. <50HP W/ NON SPECIFIC CATALYTIC REDUCTION
2310021402	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES 50-499HP W/ NSCR	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENG. 50-499HP W/ NON SPECIFIC CATALYTIC REDUCTION

SCC	Tier Description	Short Description
2310021403	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES 500+ HP W/ NSCR	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENG. 500+ HP W/ NON SPECIFIC CATALYTIC REDUCTION
2310021409	NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES W/NSCR: ALL	ON-SHORE GAS PRODUCTION NATURAL GAS FIRED 4-CYCLE RICH BURN COMPRESSOR ENGINES WITH NON-SPECIFIC CATALYTIC REDUCTION: ALL
2310021450	WELLHEAD	ON-SHORE GAS PRODUCTION: WELLHEAD
2310021500	GAS WELL COMPLETION - FLARING & VENTING	ON SHORE GAS PRODUCTION WELL COMPLETION - FLARING AND VENTING
2310021501	FUGITIVES: CONNECTORS	ON-SHORE GAS PRODUCTION: FUGITIVES: CONNECTORS
2310021502	FUGITIVES: FLANGES	ON-SHORE GAS PRODUCTION: FUGITIVES: FLANGES
2310021503	FUGITIVES: OPEN ENDED LINES	ON-SHORE GAS PRODUCTION: FUGITIVES: OPEN ENDED LINES
2310021504	FUGITIVES: PUMPS	ON-SHORE GAS PRODUCTION: FUGITIVES: PUMPS
2310021505	FUGITIVES: VALVES	ON-SHORE GAS PRODUCTION: FUGITIVES: VALVES
2310021506	FUGITIVES: OTHER	ON-SHORE GAS PRODUCTION: FUGITIVES: OTHER
2310021509	FUGITIVES: ALL PROCESSES	ON-SHORE GAS PRODUCTION: FUGITIVES: ALL PROCESSES
2310021600	GAS WELL VENTING	ON-SHORE GAS PRODUCTION GAS WELL VENTING
2310030000	TOTAL: ALL PROCESSES	OIL AND GAS EXPLORATION AND PRODUCTION: NATURAL GAS LIQUIDS
2310030210	TANKS - FLASHING & STANDING/ WORKING/ BREATHING, UNCONTROLLED	OIL AND GAS PRODUCTION NATURAL GAS LIQUIDS TANKS INCLUDING FLASH UNCONTROLLED
2310030220	TANKS - FLASHING & STANDING/ WORKING/ BREATHING, CONTROLLED	OIL & GAS PRODUCTION NATURAL GAS LIQUIDS TANKS INCLUDING FLASH CONTROLLED
2310031000	TOTAL: ALL PROCESSES	ON-SHORE OIL AND GAS EXPLORATION AND PRODUCTION: NATURAL GAS LIQUIDS
2310111000	ALL PROCESSES	ON-SHORE OIL EXPLORATION: ALL PROCESSES
2310111401	OIL WELL PNEUMATIC PUMPS	ON-SHORE OIL EXPLORATION: OIL WELL PNEUMATIC PUMPS
2310111700	OIL WELL COMPLETION: ALL PROCESSES	ON-SHORE OIL EXPLORATION: OIL WELL COMPLETION: ALL PROCESSES
2310111701	OIL WELL COMPLETION: FLARING	ON-SHORE OIL EXPLORATION: OIL WELL COMPLETION: FLARING
2310111702	OIL WELL COMPLETION: VENTING	ON-SHORE OIL EXPLORATION: OIL WELL COMPLETION: VENTING
2310121000	ALL PROCESSES	ON-SHORE GAS EXPLORATION: ALL PROCESSES
2310121401	GAS WELL PNEUMATIC PUMPS	ON-SHORE GAS EXPLORATION: GAS WELL PNEUMATIC PUMPS
2310121700	GAS WELL COMPLETION: ALL PROCESSES	ON-SHORE GAS EXPLORATION: GAS WELL COMPLETION: ALL PROCESSES
2310121701	GAS WELL COMPLETION: FLARING	ON-SHORE GAS EXPLORATION: GAS WELL COMPLETION: FLARING

SCC	Tier Description	Short Description
2310121702	GAS WELL COMPLETION: VENTING	ON-SHORE GAS EXPLORATION: GAS WELL COMPLETION: VENTING

[a] SCCs were obtained from TCEQ.

3.0 Source Types

3.1 Well Completions

Following drilling and casing, a well must be "completed." Completion is the process which enables the well to produce oil or gas. To complete the production well, casing is installed and cemented and the drilling rig is removed from the site. As the well is completed, an initial mixture of gas, hydrocarbon liquids, water, sand, and other materials comes to the surface. Standard practice during the completion process has been to vent or flare the natural gas released, some of which is VOC. This category addresses VOC emissions associated with the completion process at oil and gas wells. County-level emissions from this source will be estimated for the purpose of this inventory.

3.1.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from well completions. The relevant sources reviewed are listed in Table 3.1.

Table 3.1 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Well Completion Emissions Estimates

Report Title	Geographic Coverage	Publication Date
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin (Bar-Ilan, et al., 2009a)	Piceance Basin, Colorado	January, 2009
Development of Emissions Inventories for Natural Gas Exploration and Product Activities in the Haynesville Shale (Grant, et al., 2009)	Haynesville Shale, Texas	August, 2009

3.1.2 Emission estimation approaches

The reviewed literature provided component-based approaches for estimating releases from well completions/recompletions. One component-based method is utilized in several studies including the 2008 CENRAP study "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories" (Bar-Ilan, et al. 2008), "Development of Emissions Inventories for Natural Gas Exploration and Product Activities in the Haynesville Shale" (Grant, et al., 2009) and the "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin" (Bar-Ilan, et al., 2009a). These studies estimate the emissions per completion event based on the volume of vented gas per completion and the mass fraction of the given pollutant in the venting gas. This value is multiplied by the number completion events and takes into account destruction of a portion of the pollutant based on flaring or other “green” completion methods (methods by which emissions are minimized during well completion through capture and/or destruction of the vented gases). The “Emissions from Oil and Gas Production Facilities” (TCEQ, 2007) study uses U.S. Environmental Protection Agency’s (EPA’s) AP-42 emissions factors for CO and NO_x emissions and uses a displacement equation (mass balance approach) to estimate SO_2 and VOC emissions. Emissions are then calculated by multiplying this emissions factor by the number of completions, and the mass fraction of the given pollutant in the vented gas. The latter data may be collected via industry surveys.

3.1.3 Preferred emission estimation approach

As a preferred method to estimate emissions from well completions, ERG will use the methodology from the Central Regional Air Planning Association (CENRAP) study.

Emissions from well completions will be estimated on the basis of the volume of gas vented during completion and the average VOC content of that gas, obtained from a gas composition analyses. Emissions rates are evaluated at standard temperature and pressure (STP) in the CENRAP study. Data on the operating temperature and pressure will be collected via survey and emissions will be adjusted for the appropriate operating parameters.

The calculation methodology for completion emissions follows Equations 1 and 2:

$$E_{completion,i} = \left(\frac{P \times (V_{vented})}{(R / MW_{gas}) \times T \times 3.5 \times 10-5} \right) \times \frac{f_i}{907200} \qquad \text{Equation (1)}$$

where:

$E_{completion,i}$ is the emissions of pollutant *i* from a single completion event [ton/event]
P is atmospheric pressure [1 atm]
V_{vented} is the volume of vented gas per completion [MCF/event]
R is the universal gas constant [0.082 L-atm/mol-K]
MW_{gas} is the molecular weight of the gas [g/mol]
T is the atmospheric temperature [298 K]
f_i is the mass fraction of pollutant *i* in the vented gas

The total emissions from all completions occurring in a county can be evaluated following Equation 2:

$$E_{completion,TOTAL} = E_{completion,i} \times S_{county} \times \left(1 - 0.98 c_{flare} - c_{green}\right) \qquad \text{Equation (2)}$$

where:

$E_{completion,TOTAL}$ are the total emissions county-wide from completions [tons/year]
$E_{completion,i}$ are the completion emissions from a single completion event [tons/event]
c_{flare} is the fraction of completions in the basin controlled by flares

c_{green} is the fraction of completions in the basin controlled by green completion techniques
S_{county} is the county-wide new well and recompleted well count

Volume of vented gas per completion, V_{vented}:
The 2008 CENRAP study obtained basin-level vented gas volumes from survey data. ERG will attempt to obtain estimates for the volume of vented gas per completion by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the Texas Railroad Commission (TRC) District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average volume vented presented in the 2008 CENRAP study. The CENRAP data can also be used as a QA check to ensure that results from the survey are reasonable.

Mass fraction for a single pollutant, f_i:
The 2008 CENRAP study obtained basin-level mass fractions for various pollutants from survey data. Where survey data were not available for a specific basin, the average of all CENRAP basins was used. ERG will attempt to obtain estimates for the mass fraction of pollutants by conducting a survey of oil and gas. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average mass fractions of pollutants presented in the 2008 CENRAP study. The CENRAP data can also be used as a QA check to ensure that results from the survey are reasonable.

Number of completions controlled by flares, c_{flare} and the number of green completions, c_{green}:
The 2008 CENRAP study obtained basin-level estimates for the number of completions controlled by flares and the number of completions controlled by green completion techniques from survey data. ERG will attempt to obtain estimates for the number of completions controlled by flares or green completions either by conducting a survey of oil and gas producers, or from existing data from the TRC. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide.

County-level new/recompleted well count, S_{county}:
ERG will obtain county-level data for the number of new and recompleted wells from the TRC for each county included in this analysis.

3.1.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on the number of well completions, volume of vented gas per completion, oil and gas product composition, and number of completions controlled by flares or controlled by green completion techniques, and the number of active oil and gas wells are required. ERG will collect data on the number of oil and gas well completions per county using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.2 Well Blowdowns

Well blowdowns refer to the practice of venting gas from wells that have developed some kind of cap or obstruction before any additional intervention work can be done on the wells. Typically, well blowdowns are conducted on wells that have been shut in for a period of time and the operator desires to bring the well back into production. Well blowdowns are also sometimes conducted to remove fluid caps that have built up in producing gas wells. Because gas is directly vented from the blowdown event, blowdowns can be a source of VOC emissions. County-level emissions from this source will be estimated for the purpose of this inventory.

3.2.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from well blowdowns. The relevant sources reviewed are listed in Table 3.2.

Table 3.2 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Well Blowdown Emissions Estimates

Report Title	Geographic Coverage	Publication Date
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin (Bar-Ilan, et al., 2009a)	Piceance Basin, Colorado	January, 2009
Development of Emissions Inventories for Natural Gas Exploration and Product Activities in the Haynesville Shale (Grant, et al., 2009)	Haynesville Shale, Texas	August, 2009

3.2.2 Emission estimation approaches

The reviewed literature provided component-based approaches for estimating releases from well blowdowns. One component-based method is utilized in several studies including the 2008 CENRAP study "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories" (Bar-Ilan, et al. 2008), "Development of Emissions Inventories for Natural Gas Exploration and Product Activities in the Haynesville Shale" (Grant, et al., 2009) and the "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin" (Bar-Ilan, et al., 2009a). Emissions from blowdowns are estimated on the basis of the volume of gas vented during a blowdown and the average pollutant content of that gas, obtained from gas composition analyses. This methodology is very similar to that of completion venting. Flaring and/or green practices may be used to control emissions from the blowdown process.

The previous ERG study, “Emissions from Oil and Gas Production Facilities” (TCEQ, 2007), did not estimate emissions from well blowdowns.

3.2.3 Preferred emission estimation approach

As a preferred method, ERG will use the methodology from the CENRAP study to generate estimated emissions from well blowdowns.

Emissions from well blowdowns will be estimated on the basis of the volume of gas vented during blowdown and the average VOC content of that gas, obtained from a gas composition analyses. Emissions rates are evaluated at STP in the CENRAP study. Data on the operating temperature and pressure will be collected via survey and emissions will be adjusted for the appropriate operating parameters.

The calculation methodology for blowdown emissions is identical to the method for completion emissions, and follows Equations 3 and 4:

$$E_{blowdown,i} = \left(\frac{P \times (V_{vented})}{(R/MW_{gas}) \times T \times 3.5 \times 10-5} \right) \times \frac{f_i}{907200} \qquad \text{Equation (3)}$$

where:

$E_{completion,i}$ is the emissions of pollutant i from a single blowdown event [ton/event]
P is atmospheric pressure [1 atm]
V_{vented} is the volume of vented gas per blowdown [MCF/event]
R is the universal gas constant [0.082 L-atm/mol-K]
MW_{gas} is the molecular weight of the gas [g/mol]
T is the atmospheric temperature [298 K]
f_i is the mass fraction of pollutant i in the vented gas

The total emissions from all blowdowns occurring in a county can be evaluated following Equation 4:

$$E_{blowdown,TOTAL} = E_{blowdown,i} \times N_{blowdown} \times N_{wells} \times (1 - 0.98c_{flare} - c_{green}) \qquad \text{Equation (4)}$$

where:

$E_{blowdown,TOTAL}$ are the total emissions county-wide from blowdowns [tons/year]
$E_{blowdown,i}$ are the blowdown emissions from a single blowdown event [tons/event]
$N_{blowdown}$ is the number of blowdowns per well in the county
N_{wells} is the total number of active wells in the county
c_{flare} is the fraction of blowdowns in the basin controlled by flares
c_{green} is the fraction of blowdowns in the basin controlled by green completion techniques

Volume of vented gas per blowdown, V_{vented}:
The 2008 CENRAP study obtained basin-level vented gas volumes from survey data. ERG will attempt to obtain estimates for the volume of vented gas per blowdown by conducting a survey of oil and gas producers. In the event that insufficient data is collected on a particular county, ERG will use the average of all other counties. If insufficient data is collected on all counties, ERG may default to the average volume vented presented in the 2008 CENRAP study. The CENRAP data can also be used as a Quality Assurance (QA) check to ensure that results from the survey are reasonable.

Mass fraction for a single pollutant, f_i:
The 2008 CENRAP study obtained basin-level mass fractions for various pollutants from survey data. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. ERG will attempt to obtain estimates for the mass fraction of pollutants by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average mass fractions of pollutants presented in the 2008 CENRAP study. The CENRAP data can also be used as a QA check to ensure that results from the survey are reasonable.

County-level number of blowdowns per well, $N_{blowdown}$:
The 2008 CENRAP study obtained basin-level number of blowdowns from survey data. ERG will attempt to obtain estimates for the number of blowdowns per county by conducting a survey of oil and gas producers. In the event that insufficient data is collected on a particular county, ERG will use the average of all other counties. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average mass fractions of pollutants presented in the 2008 CENRAP study. The CENRAP data can also be used as a QA check to ensure that results from the survey are reasonable.

County-level well count, N_{wells}:
The 2008 CENRAP study obtained basin-level number of wells from survey data. ERG will attempt to obtain estimates for the number of wells per county by conducting a survey of oil and gas producers. In the event that insufficient data is collected on a particular county, ERG will use the average of all other counties. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average mass fractions of pollutants presented in the 2008 CENRAP study. The CENRAP data can also be used as a QA check to ensure that results from the survey are reasonable.

Number of blowdowns controlled by flares, c_{flare} and the number of green blowdowns, c_{green}:
The 2008 CENRAP study obtained basin-level estimates for the number of blowdowns controlled by flares and the number of blowdowns controlled by green techniques from survey data. ERG will attempt to obtain county-level estimates for the number of blowdowns controlled by flares or green blowdown methods either by conducting a survey of oil and gas producers, or

from existing data from the TRC. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide.

3.2.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on the number of well blowdowns, volume of vented gas per blowdown, oil and gas product composition, and number of blowdowns controlled by flares or controlled by green techniques, and the number of active oil and gas wells are required. ERG will collect data on the number of oil and gas wells per county using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.3 Wellheads

The wellhead is the part of an oil or gas well that terminates at the surface and is the location where oil or gas products can be withdrawn. The primary function of the wellhead is to hold the casings and the production tubing of the well. On top of the wellhead sits the tubing hanger, from which the production tubing is run. The well christmas tree rests on top of the tubing hanger, as well as surface flow-control facilities used in the production phase of the well. The wellhead is a source of VOC emissions from various fugitive outlets including seals and joints. County-level emissions from this source will be estimated for the purpose of this inventory.

3.3.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from emissions generated at oil and gas wellheads. The relevant sources reviewed are listed in Table 3.3.

Table 3.3 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Wellhead Emissions Estimates

Report Title	Geographic Coverage	Publication Date
Oil and Gas Emission Inventories for the Western States (Russell, et al., 2005)	WRAP States	December, 2005
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007

3.3.2 Emission estimation approaches

The reviewed literature provided two similar approaches to estimate emissions from wellheads at oil and gas sites. The first of these approaches is presented in the study: "Oil and Gas Emission Inventories for the Western States" (Russell, et al., 2005), which uses oil and gas production data along with emission factors for various wellhead sources to determine wellhead emissions. These sources include: tanks, dehydrators, heaters, completions, and pneumatic devices.

Emissions from all of these sources are discussed elsewhere in this report. The "Emissions from Oil and Gas Production Facilities" (TCEQ, 2007) study uses AP-42 emission factors for oil and gas facilities to determine wellhead emissions from wellhead assemblies and rod pumps. Other reviewed sources did not provide wellhead emissions calculation methodologies.

3.3.3 Preferred emission estimation approach

As a preferred method to estimate emissions from wellheads, ERG will use the AP-42 emission factor to calculate emissions from oil and gas wellheads, based on the number of oil and gas wellheads in place. The AP-42 emission factor for VOC emissions from gas wellheads is based on gas production. Gas production data by county in Texas is also available from the TRC. However, additional emission methodologies may be developed if additional sources are located.

3.3.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on the number of oil wellheads and gas production are required. ERG will collect data on the number of oil wellheads and gas production wellhead sites per county using the most recently available database from the TRC.

3.4 Pneumatic Devices

Pneumatic devices are used for a variety of gas and oil well processes and are powered by high-pressure produced gas. These devices include transducers, liquid level controllers, pressure controllers and positioners. During the normal operation of these devices, they release or bleed natural gas to the atmosphere making them a source of VOC emissions. County-level emissions from these sources will be estimated for the purpose of this inventory.

3.4.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from emissions generated by pneumatic devices typically utilized at oil and natural gas production wells. The relevant sources reviewed are listed in Table 3.4.

Table 3.4 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Pneumatic Device Emissions Estimates

Report Title	Geographic Coverage	Publication Date
Oil and Gas Emission Inventories for the Western States (Russell, et al., 2005)	WRAP States	December, 2005
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007

Table 3.4 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Pneumatic Device Emissions Estimates (Cont.)

Report Title	Geographic Coverage	Publication Date
WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II (Bar-Ilan, et al., 2007)	WRAP States	September, 2007
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin (Bar-Ilan, et al., 2009a)	Piceance Basin, Colorado	January, 2009

3.4.2 Emission estimation approaches

The reviewed literature provided two similar approaches with different bases to estimate emissions from pneumatic devices at oil and gas sites. The first of these approaches is presented in the Western Regional Air Partnership (WRAP) Phase I (Russell, et al., 2005) and WRAP Phase II (Bar-Ilan, et al., 2007) reports which utilize separate emissions factors for oil wells and gas wells provided by the Wyoming Department of Environmental Quality (WYDEQ). The emissions factors for VOC and Hazardous Air Pollutants (HAPs) from pumps are given on a per well basis (tons/yr/well) and are calculated based on an average usage/bleed rate of 5 scf/hr, statewide average weighted gas compositions, continuous operation, and an assumption of two pumps per gas well and one pump per oil well. Area-wide emissions are then calculated based on the number of gas wells and oil wells currently active in a specific area. This approach was also adopted in the 2007 TCEQ report on emissions from oil and gas production facilities. However, the emissions factors were recalculated using weight percents provided in a 2004 report from the Gas Processors Association (GPA).

An alternative approach is presented in both the 2008 CENRAP study "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories" (Bar-Ilan, et al. 2008) and "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin" (Bar-Ilan, et al., 2009a). The same calculation approach is used in this method; however, this method uses bleed rates obtained from the results of an extensive study performed by EPA as part of the Natural Gas Star program in 2004. This study provides bleed rate estimates for several different device types – liquid level controllers, positioners, pressure controllers, and transducers. This approach also conducted a survey to estimate the number of each device type present at typical gas and oil well sites. Given the additional level of detail presented with this approach, it will be the preferred approach for estimating emissions from pneumatic devices.

3.4.3 Preferred emission estimation approach

As a preferred method to estimate emissions from pneumatic devices, ERG will use the CENRAP methodology.

Emissions from a single well site are calculated using Equation 5:

$$E_{pneumatic,j} = \frac{f_j}{907200}\left(\sum_i V_i \times N_i \times t_{annual}\right) \times \frac{P}{\left(\frac{R}{MW_{gas}}\right) \times T \times 3.5 \times 10^{-5}} \qquad \text{Equation (5)}$$

where:

$E_{pneumatic,j}$ is the total emissions of pollutant j from all pneumatic devices for a typical well [ton/year/well]
V_i is the volumetric bleed rate from device i [scf/hr/device]
N_i is the total number of device i owned by the participating companies
t_{annual} is the number of hours per year that devices are operating
P is the atmospheric pressure [1 atm]
R is the universal gas constant [0.082 L-atm/mol-K]
MW_{gas} is the molecular weight of the gas [g/mol]
T is the atmospheric temperature [298 K]
f_j is the mass fraction of pollutant j in the vented gas

County-wide emissions are calculated using Equation 6:

$$E_{pneumatic,TOTAL} = E_{pneumatic,j} \times N_{well} \qquad \text{Equation (6)}$$

where:

$E_{pneumatic,TOTAL}$ is the total pneumatic device emissions in the county [ton/yr]
$E_{pneumatic,j}$ is the pneumatic device emissions for a single well of pollutant j [ton/yr]
N_{well} is the total number of active wells in the county for a given year

Emissions rates are evaluated at STP in the CENRAP study. Data on the operating temperature and pressure will be collected via survey and emissions will be adjusted for the appropriate operating parameters.

Volumetric bleed rate from device i, V_i:
The 2008 CENRAP study uses bleed rates for various devices presented in a 2004 EPA Natural Gas Star program study. ERG will also use the bleed rates from the EPA Natural Gas Star program study when calculating emissions from pneumatic devices at oil and gas production sites.

Total number of devices, N_i:
The 2008 CENRAP study obtained basin-level total number of devices per well from survey data. Where survey data was not available for a specific basin, the average of all CENRAP

basins was used. ERG will attempt to obtain estimates for the number of devices per well by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of number of devices for each type presented in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Number of hours per year that devices are operating, t_{annual}:
The 2008 CENRAP study assumed basin-level annual hours of device operation to be 8760 hr/yr (non-stop operation). ERG will attempt to obtain estimates for the annual hours of device operation by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to a value of 8760 hr/yr assumed in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Molecular weight of gas, MW_{gas}:
The 2008 CENRAP study obtained basin-level molecular weights of gas bleeding from survey data. ERG will attempt to obtain data on the molecular weights by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of the molecular weights in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Mass fraction of pollutant j in the vented gas, f_j:
The 2008 CENRAP study obtained basin-level mass fractions from survey data. ERG will attempt to obtain estimates for the mass fractions of pollutants by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the compositions presented in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

3.4.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on the number of devices per well, annual hours of device operation, oil and gas product composition and molecular weight, and number of active oil and gas wells are required. ERG will collect data on the number of oil and gas wells per county using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.5 Fugitive Emissions (Equipment Leaks)

All oil and gas producing sites have a system of pumps and piping to transport oil and gas from the wellhead to the processing area. These pumps and piping networks are constructed with many individual components including flanges, valves, seals, and connectors. As a result of high operating pressures, varying fitting tightness, and age and condition, each of these components has the potential to release fugitive emissions while oil and gas product flows through them. County-level emissions from these sources will be estimated for the purpose of this inventory.

3.5.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from fugitive emissions generated by non-point source equipment and components typically utilized at oil and natural gas production wells. The relevant sources reviewed are listed in Table 3.5.

Table 3.5 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Fugitive Emissions Estimates

Report Title	Geographic Coverage	Publication Date
Ozone Precursors Emissions Inventory for San Juan and Rio Arriba Counties, New Mexico (Pollack, et al., 2006)	San Juan and Rio Arriba Counties, New Mexico	August, 2006
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin (Bar-Ilan, et al., 2009a)	Piceance Basin, Colorado	January, 2009

3.5.2 Emission estimation approaches

The reviewed literature sources all provided a similar approach for estimating fugitive emissions from equipment leaks. This method estimates emissions using component-based emissions factors. The component-based method uses EPA's AP-42 emissions factors for each component type based on the type of service to which the equipment applies – gas, light liquid, heavy liquid, or water. Emissions are then calculated by multiplying this emissions factor by the number of components per well, the annual number of hours the well is in operation, and the mass fraction of the given pollutant in the vented gas. The latter data were collected via industry surveys. These well-based emissions are then multiplied by the number of wells for a given area. The 2007 TCEQ study uses emissions factors developed by the American Petroleum Institute (API), and the number of components per well was obtained from a study conducted by the Canadian Association of Petroleum Producers (CAPP).

The component-based method applies to both oil and gas producing wells. If sufficient data on the number of components at each well site can be obtained, performing a component-based analysis will allow for the most comprehensive estimates for fugitive releases.

3.5.3 Preferred emission estimation approach

As a preferred method to estimate fugitive emissions from equipment leaks, ERG will use the CENRAP methodology.

Fugitive emissions from a single well site may be calculated using Equation 7:

$$E_{fugitive,j} = \sum_i EF_i \times N_i \times t_{annual} \times Y_j \times 0.0011 \qquad \text{Equation (7)}$$

where:

$E_{fugitive,j}$ is the fugitive emissions for a single typical well for pollutant j [ton/yr/well]
EF_i is the emission factor of TOC for a single component i [kg/hr/component]
N_i is the total number of components of type i
t_{annual} is the annual number of hours the well is in operation [hr/yr]
Y_j is the mass fraction of pollutant j to TOC in the vented gas

County-wide fugitive emissions are calculated using Equation 8:

$$E_{fugitive,TOTAL} = E_{fugitive,j} \times N_{well} \qquad \text{Equation (8)}$$

where:

$E_{fugitive,TOTAL}$ is the total fugitive emission in the county [ton/yr]
$E_{fugitive,j}$ is the fugitive emissions for a single well of pollutant j [ton/yr]
N_{well} is the total number of active wells in the county for a given year

Emissions rates are evaluated at STP in the CENRAP study. Data on the operating temperature and pressure will be collected via survey and emissions will be adjusted for the appropriate operating parameters.

Emission factor of TOC for a single component, EF_i:
ERG will use EPA's AP-42 emissions factors when calculating fugitive emissions from equipment leaks at oil and gas production sites.

Total number of components, N_i:
The 2008 CENRAP study obtained basin-level total number of components per well from survey data. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. ERG will attempt to obtain estimates for the number of components per well by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-

wide. If insufficient data is collected on all counties, ERG may default to the average number of components for each service type presented in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Annual number of hours the well is in operation, t_{annual}:
The 2008 CENRAP study assumed basin-level annual hours of well operation to be 8760 hr/yr (non-stop operation). ERG will attempt to obtain estimates for the annual hours of well operation by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to a value of 8760 hr/yr assumed in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Mass fraction of pollutant j to TOC in the vented gas, Y_j:
The 2008 CENRAP study obtained basin-level mass fractions from survey data. ERG will attempt to obtain estimates for the mass fractions of pollutants by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the compositions presented in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

3.5.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on the number of components per well, annual hours of well operation, oil and gas product composition, and number of active oil and gas wells are required. ERG will collect data on the number of oil and gas wells per county using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.6 Artificial Lift (Pumpjack) Engines

A pumpjack is used to mechanically lift liquid out of the well if there is not enough bottom hole pressure for the liquid to flow all the way to the surface. The pumpjack can be driven by an electric motor; however, in isolated locations without access to electricity, combustion engines are used. The most common "off-grid" pumpjack engines run on casing gas produced from the well, but pumpjacks have been run on many types of fuel, such as propane (LPG) and diesel. Generally, pumpjacks have smaller engines than wellhead compressor engines, but they operate continuously (8760 hours per year) with minimum down-time. For this project, criteria pollutant emissions from pumpjack engines will be estimated.

3.6.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from artificial lift pumpjack engines. The relevant sources reviewed are listed in Table 3.6.

Table 3.6 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Artificial Lift (Pumpjack) Engines

Report Title	Geographic Coverage	Publication Date
Natural Gas Compressor Engine Survey and Engine NOx Emissions at Gas Production Facilities (HARC, 2005)	Eastern Portion of Texas	August, 2005
Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico (Pollack, et al., 2006)	San Juan and Rio Arriba Counties, New Mexico	August, 2006
Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities (HARC, 2006)	Eastern Portion of Texas	October, 2006
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008

3.6.2 Emission estimation approaches

Of the studies reviewed, there was basically only one methodology used in determining emissions from pumpjack engines. The 2008 study conducted by ENIRON entitled: "Recommendations for Improvements to the CENRAP States' Oil and Gas Emission Inventories" (Bar-Ilan, et al., 2008), applies pollutant specific emission factors (g/hp-hr) to various data gathered from an inventory of artificial lift engines (based off of surveyed companies). The data consisted of engine specific information including horsepower, load factors, and actual hours operated. The emissions were scaled up to the basin level on the basis of well counts and then scaled to county-level using the fraction of total oil production from oil wells located in each county. All engine emissions factors (except those for SO_2) were obtained from the EPA's NONROAD model (EPA, 2005), which contains default emissions factors for an artificial lift natural gas fired engine. A similar methodology was used to calculate emissions from artificial pumpjack engines in the 2006 study entitled: "Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico" (Pollack, et al., 2006). However, the emission factors used in the 2006 New Mexico study were based on survey data of specific engine types/categories and their manufacturers' emission rates instead of the EPA's NONROAD model. The specific methodology from these two studies is discussed in Section 3.6.3.

As an alternative to the methodology used in the CENRAP 2008 and the 2006 New Mexico studies, ERG explored the idea of applying the methodology we have proposed for estimating emissions from compressor engines (see Section 3.11) to determine emissions from pumpjack engines. We believe this approach would be optimal when calculating pumpjack emissions at the county level because it would not require knowing the specific count of pumpjack engines, nor their individual sizes. However, the approach would require ERG to develop power-to-pump requirements (Hp-hr/bbl) which are certain to vary with the depth of the oil in each well and may also depend on other factors such as plunger/equipment variations. ERG will attempt to obtain the required data to implement this methodology (pumpjack engine size, hours of operation, engine loads, well depth, and production data for each well) through the industry survey. Depending upon the response rate to the survey, ERG may be able to proceed with this approach and develop power-to-pump requirements in terms of Hp-hr/bbl based on engine size, hours of operation, and oil production data. At this point, we consider this to be an alternative approach.

3.6.3 Preferred emission estimation approach

ERG will use the methodology from the 2008 CENRAP study to generate estimated emissions from pumpjack engines. The calculation methodology for this particular approach is shown in Equations 9 and 10:

$$E_{engine} = \frac{EF_i \times HP \times LF \times t_{annual}}{907{,}185} \qquad \text{Equation (9)}$$

where:

E_{engine} are emissions from a pumpjack engine [ton/year/engine]
EF_i is the emissions factor of pollutant i [g/hp-hr]
HP is the horsepower of the engine [hp]
LF is the load factor of the engine
t_{annual} is the annual number of hours the engine is used [hr/yr]

County-wide pumpjack engine emissions would then be calculated using Equation (10):

$$E_{engine,TOTAL} = E_{engine} \times W_{TOTAL} \times f_{pumpjack} \times (1 - e_{pumpjack}) \qquad \text{Equation (10)}$$

where:

$E_{engine,TOTAL}$ is the total emissions from pumpjack engines in the county [ton/yr]
E_{engine} is the total emissions from a pumpjack engine [ton/yr]
W_{TOTAL} is the total number of wells in the county
$f_{pumpjack}$ is the fraction of oil wells with pumpjack engines
$e_{pumpjack}$ is the fraction of pumpjack engines that are electrified

3.6.4 Data Needs

ERG will implement the approach used in the 2008 CENRAP study and 2006 New Mexico study to estimate emissions from pumpjack engines. In order to perform the emission calculations, information on engine ratings, load factors, annual hours of engine operation and county-level data of the number of oil wells with and without pumpjack engines is required. ERG will collect data on the number of oil wells per county using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active oil wells in the Texas counties covered in this emissions inventory development effort.

If the industry response is sufficient, ERG may attempt to develop power-to-pump requirements (Hp-hr/bbl) for pumpjack engines to implement the alternative approach.

3.7 Heaters and Boilers

The purpose of heaters and boilers at oil and gas production facilities is to provide thermal energy input to certain operations within the production process. They can be used as separator heaters (heater treaters) to provide heat input to separation units, as tank heaters to maintain storage tank temperatures, or as inline heaters to maintain temperature within pipes and connections. Heaters and boilers may also be used in dehydrators; however, these sources will be covered under the dehydrator source methodology of this report. Heaters and boilers are typically natural gas-fired external combustors. They are primarily considered a source of NO_x, as well as a minor source of CO, VOC and PM emissions. SO_2 emissions may also occur if the gas used to fire the heaters contains Hydrogen Sulfide (H_2S) which will be subsequently converted to SO_2 during combustion. County-level emissions from heater sources will be estimated for the purpose of this inventory.

3.7.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from emissions generated by heaters and boilers typically utilized at oil and natural gas production wells. The relevant sources reviewed are listed in Table 3.7.

Table 3.7 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Heater and Boiler Emissions Estimates

Report Title	Geographic Coverage	Publication Date
Oil and Gas Emission Inventories for the Western States (Russell, et al., 2005)	WRAP States	December, 2005
Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico (Pollack, et al., 2006)	San Juan and Rio Arriba Counties, New Mexico	August, 2006
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007

Table 3.7 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Heater and Boiler Emissions Estimates (Cont.)

Report Title	Geographic Coverage	Publication Date
WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II (Bar-Ilan, et al., 2007)	WRAP States	September, 2007
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin (Bar-Ilan, et al., 2009a)	Piceance Basin, Colorado	January, 2009

3.7.2 Emission estimation approaches

The reviewed literature provided two different approaches to estimating emissions from heaters and boilers at oil and gas sites. The first of these approaches is presented in the WRAP Phase I report "Oil and Gas Emission Inventories for the Western States" (Russell, et al., 2005) and WRAP Phase II report "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II" (Bar-Ilan, et al., 2007). This approach will subsequently be referred to as Method 1. Method 1 utilizes separate emissions factors for oil wells and gas wells provided by the WYDEQ. The emissions factors for gas wells are given on a per well basis (lbs/yr per well) and oil well emissions factors are given on a per barrel produced basis (lbs/barrel). Area-wide emissions are then calculated based on the number of gas wells and barrels of oil produced in a specific area. Method 1 was also adopted in the 2007 TCEQ report on emissions from oil and gas production facilities.

An alternative approach to estimate emissions from heaters and boilers was presented in the 2008 CENRAP report "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories" (Bar-Ilan, et al. 2008) and the Piceance Basin study "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin" (Bar-Ilan, et al., 2009a) from the Independent Petroleum Association of Mountain States (IPMAS)/WRAP Phase III reports. This approach will subsequently be referred to as Method 2. For Method 2, emissions of a particular pollutant from a single heater are based on the emissions factor of the heater, the annual flow rate of gas and the annual operating time of the heater. The gas flow is derived from the rating of the heater and the local natural gas heating value. All emissions factors used were based on EPA's AP-42 emissions factors for natural gas-fired heaters provided under the external combustion sources category. An additional heater cycling fraction factor was also incorporated which takes into account the fraction of operating hours that the heater is actually firing. The 2008 CENRAP report also provides a separate methodology for estimating SO_2 emissions by estimating the mass of gas combusted in the heater using the ideal gas law and then utilizing the mass fraction of H_2S in the gas assuming 100 percent conversion to SO_2. Basin-wide emissions were then estimated by determining the typical number of heaters per well and scaling up by well count. These estimates were then expanded to the county-level by allocating the total basin-wide heater emissions into each county according to the fraction of basin total wells that are located in each county.

Between the two methodologies, Method 2 provides a fundamental, bottom-up approach which allows for emissions to be estimated based on site-specific parameters and results in a more accurate and dynamic emissions inventory for heaters and boilers. Method 1 uses emissions factors which are previously calculated based on industry-wide averages for heater ratings and gas heating values specific to Wyoming, resulting in a lack of flexibility and detail as compared to Method 2. Additionally, Method 2 incorporates a scaling factor based on the number of heaters per well to supplement the scaling factor for the total number of wells. This level of detail is advantageous and allows for an additional layer of data collection when calculating emissions on the county-level. This is not captured in Method 1 which only accounts for the total number of wells.

There are some short-comings with Method 2 that will need to be addressed in the development of this current emissions inventory. Due to lack of detail in the utilized databases, a breakdown of emissions by well type (i.e. oil or gas) was not available. Additionally, county-level emissions were derived from the allocation of basin-wide emissions based on the fraction of wells located in each county. The development of the updated TCEQ emissions inventory will attempt to obtain county-level data by well type in all aspects of the analysis to obtain a more accurate model of emissions from county to county.

3.7.3 Preferred emission estimation approach

As a preferred method to estimate emissions from heaters and boilers, ERG will use the CENRAP methodology.

Emissions from a single heater may be calculated using Equation 11 (excluding SO_2 emissions):

$$E_{heater} = \frac{EF_{heater} \times Q_{heater} \times t_{annual} \times hc}{\left(HV_{local} \times 10^6 \times 2000\right)} \qquad \text{Equation (11)}$$

where:

E_{heater} is the emissions from a given heater [ton/yr]
EF_{heater} is the emission factor for a heater for a given pollutant [lb/MMSCF]
Q_{heater} is the heater MMBTU/hr rating [$\mathrm{MMBTU_{rated}}$/hr]
HV_{local} is the local natural gas heating value [$\mathrm{MMBTU_{local}}$/scf]
t_{annual} is the annual hours of operation [hr/yr]
hc is the heater cycling fraction to account for the fraction of operating hours that the heater is firing.

SO_2 emissions from a single heater may be calculated using Equation 12:

$$E_{heater,SO_2} = \frac{2 \times f_{H_2S}}{907200} \times \left(\frac{Q_{heater} \times t_{annual} \times hc}{HV_{local}} \times \frac{P}{\left(\frac{R}{MW_{gas}}\right) \times T \times 0.035} \right) \qquad \text{Equation (12)}$$

where:

$E_{heater,SO2}$ is the SO_2 emissions from a given heater [ton-SO_2/yr]
f_{H2S} is the mass fraction of H_2S in the gas
Q_{heater} is the heater MMBTU/hr rating [$MMBTU_{rated}$/hr]
t_{annual} is the annual hours of operation [hr/yr]
hc is the heater cycling fraction to account for the fraction of operating hours that the heater is firing.
HV_{local} is the local natural gas heating value [$MMBTU_{local}$/scf]
P is atmospheric pressure [1 atm]
R is the universal gas constant [0.082 L-atm/mol-K]
MW_{gas} is the molecular weight of the gas [g/mol]

The total emissions generated by heaters and boilers from specific county are calculated using Equation 13:

$$E_{heater,TOTAL} = \left(E_{heater} + E_{heater,SO_2}\right) \times N_{heater} \times \frac{W_{TOTAL}}{2000} \qquad \text{Equation (13)}$$

where:

$E_{heater,TOTAL}$ is the total heater emissions in the county [ton/yr]
E_{heater} is the total emissions from a single heater [ton/yr]
$E_{heater,SO2}$ is the total SO_2 emissions from a single heater [ton-SO_2/yr]
W_{TOTAL} is the total number of wells in the county
N_{heater} is the typical number of heaters per well in the county

<u>Emission factor for a heater for a given pollutant, E_{heater}:</u>
ERG will use EPA's AP-42 emissions factors when calculating emissions from heaters and boilers at oil and gas production sites.

<u>Heater MMBTU/hr rating, Q_{heater}:</u>
The 2008 CENRAP study obtained basin-level heater firing rates from survey data. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. ERG will attempt to obtain heater firing rates by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of the heater firing rate values presented in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Local natural gas heating value, HV_{local}:
The 2008 CENRAP study attempted to collect basin-level local heating values from survey data. However, the responses for the request of the value were insufficient; therefore, the average natural gas heating value from the IPAMS/WRAP Phase III analysis was used. ERG will attempt to obtain local heating values by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the local natural gas heating value presented in the 2008 CENRAP study originally taken from the IPAMS/WRAP Phase III study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Annual hours of operation, t_{annual}:
The 2008 CENRAP study obtained basin-level annual hours of operation for heaters from survey data. ERG will attempt to obtain data on the annual hours of operation for heaters and boilers by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of the annual operation hours presented in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Heater cycling fraction, *hc*:
The 2008 CENRAP study obtained basin-level heater cycling fractions from survey data. A heater cycling fraction of 1 was obtained for all responding basins. ERG will attempt to obtain data on the heater cycling fraction by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to a value of 1 as used in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Mass fraction of H_2S, f_{H2S}:
The 2008 CENRAP study obtained basin-level mass fractions of H_2S in the gas used to fire the heaters and boilers from survey data. ERG will attempt to obtain data on the mass fraction of H_2S by conducting a survey of oil and gas producers, or from the TRC. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of the H_2S mass fractions in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Molecular weight of gas, MW_{gas}:
The 2008 CENRAP study obtained basin-level molecular weights of gas used to fire the heaters and boilers from survey data. ERG will attempt to obtain data on the molecular weights by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of the molecular weights in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

Typical number of heater per well, N_{heater}:
The 2008 CENRAP study obtained basin-level typical number of heaters per well from survey data. ERG will attempt to obtain data on the number of heaters per well by conducting a survey of oil and gas producers. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide. If insufficient data is collected on all counties, ERG may default to the average of the number of heaters per well in the 2008 CENRAP study. The CENRAP data can also be used as a quality assurance check to ensure that results from the survey are reasonable.

3.7.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on the number of heaters and boilers per well, annual hours of heater operation, heater ratings, local natural gas heating values, heater cycling fractions, gas molecular weight and H_2S content, and number of active oil and gas wells are required. ERG will collect data on the number of oil and gas wells per county using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.8 Dehydrators

Oil and natural gas, when first pumped from the ground, may contain a mixture of liquid and gaseous organic compounds, nitrogen, carbon dioxide, water, sand, and other impurities. The extracted product is passed through a three-phase separator. The separator allows the water, oil and gas to separate. The gaseous component is then piped to a dehydrator to remove any remaining moisture, improving its quality for sale, and to help prevent corrosion in downstream pipelines.

The most common and economical process for dehydrating natural gas is to contact the gas with a hygroscopic liquid such as one of the glycols. Glycol dehydration is an absorption process, where the water vapor in the gas stream becomes dissolved in a relatively pure stream of glycol liquid solvent, removing the water from the natural gas. This process is completed in an absorption column. After the water is removed from the gas stream, the gas is pumped to a gas transmission pipeline. During the absorption process, the glycol also absorbs some methane and VOC.

After leaving the absorber, the water-rich glycol is de-pressurized. This step is necessary as the absorber is typically operated at high pressure. The pressure must be reduced before the regeneration step. This step may occur in a flash vessel, if the dehydration system is equipped with one, or it may occur in the glycol regenerator vessel. If the water-rich glycol is first fed to a flash vessel, the hydrocarbon vapors are vented and any liquid hydrocarbons are skimmed from the glycol. The de-pressurization step is the primary source of VOC emissions from dehydrator systems.

The glycol is regenerated by boiling the water out of the glycol. The water-rich glycol is pumped into a vented boiler vessel called a glycol regenerator boiler. Heat is added until the temperature of the mixture is greater than 212 degrees (the boiling point of water), but less than 400 degrees (the boiling point of glycol). The regeneration step allows the glycol to be purified and recovered for reuse with minimal loss of glycol. Any VOCs remaining in the glycol are volatized and vented to the atmosphere. The glycol regeneration step involves burning a fuel in a boiler to heat the glycol-water mixture. The combustion results in emissions of NO_X and CO, and small amounts of PM_{10}, SO_2, VOC, and HAPs.

In summary, the two discreet units in a dehydrator system that generate pollutant emissions are the flash vessel (if present) and the glycol regenerator boiler. The flash vessel and glycol regenerator normally vent methane, VOC, and HAP during normal, uncontrolled operation, while the glycol regenerator boiler also has combustion emissions.

3.8.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from dehydrators. The relevant sources reviewed are listed in Table 3.8.

Table 3.8 Existing Oil and Gas Exploration Emissions Studies

Report Title	Geographic Coverage	Publication Date
Oil and Gas Emission Inventories for the Western States (Russell, et al., 2005)	WRAP States	December 2005
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II (Bar-Ilan, et al., 2007)	WRAP States	September, 2007
Development of Baseline 2006 Emissions from Oil and Gas Activity in the South San Juan Basin (Bar-Ilan, et al., 2009b)	New Mexico	November, 2009
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Development of Emissions Inventories for Natural Gas Exploration and Production Activity in the Haynesville Shale (Grant, et al., 2009)	Haynesville Shale, Texas & Louisiana	August 2009

3.8.2 Emission Estimation Approaches

The reviewed literature provided both component-based and production-based approaches for estimating emissions from dehydrator flash vessels, glycol regenerator vents, and glycol regenerator boilers.

The 2005 WRAP Phase I study "Oil and Gas Emission Inventories for the Western States" (Russell, et al., 2005), the 2007 WRAP Phase II study "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II" (Bar-Ilan, et al., 2007), and the 2007 TCEQ study "Emissions from Oil and Gas Production Facilities" estimated uncontrolled VOC emissions from dehydrator flash vessels and glycol regenerator vents using a gas production-based emission factor provided by the WYDEQ. The emission factor was multiplied by well-specific gas production figures obtained from the State oil and gas commissions. The Wyoming emission factor was derived by calculating a production-weighted average composition of wet gas for each formation across the state. The weighted average was then used with GlyCalc modeling software to calculate emission factors based on one million standard cubic foot of gas per day (MSCFD). This methodology is not preferred for the 2008 inventory as the emission factor is based on gas composition data from Wyoming.

The 2009 WRAP Phase III study "Development of Baseline 2006 Emissions from Oil and Gas Activity in the South San Juan Basin" (Bar-Ilan, et al., 2009b) utilized a similar approach to estimating emissions from dehydrator flash vessels and glycol regenerator vents as was done in the WRAP Phase I study. Emissions from glycol regenerator boilers were calculated using AP-42 emission factors and the limited data available for field dehydrators to produce an emission factor on a per-unit-of-gas-throughput basis. This emission factor was applied to basin-wide gas production rates to determine basin-wide emissions from the regenerator boilers.

The 2008 CENRAP study "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories" (Bar-Ilan, et al., 2008) utilized the same approach to estimating emissions as was done in the WRAP Phase III study, except for the Texas basins. For Texas basins, the VOC emissions from dehydrator flash vessels were estimated with GlyCalc software using data on the composition of wellhead gas for each of the basins. This gas composition data were obtained from Northeast Texas Air Care (NETAC) and TCEQ and was based on sampling. This emission factor was applied to all gas production in each basin to derive basin-wide emissions estimates for dehydrator flash vessels and glycol regenerator vents. Emissions from glycol regenerator boilers were calculated using AP-42 emission factors to produce an emission factor on a per-unit of gas throughput basis. This emission factor was applied to all gas production in each basin to derive basin-wide emissions estimates for glycol regenerator boilers. This methodology was also used in the 2009 study "Development of Emissions Inventories for Natural Gas Exploration and Production Activity in the Haynesville Shale" (Grant, et al., 2009) for the East Texas Basin.

The reviewed literature also addressed the effect of dehydrator system control technologies on emissions. The 2007 WRAP Phase II study "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II" (Bar-Ilan, et al. 2007) evaluated three strategies or technologies for controlling VOC and HAP emissions from dehydrator systems. These are: optimize glycol circulation rate, install electric pumps, and install flash tank separators.

- **Optimizing Glycol Recirculation Rate:** The study determined that VOC emissions could be reduced by 33 to 67 percent by optimizing the glycol circulation rate. Glycol recirculation rate is set for the optimal rate based on the initial rate of gas production at a well. However, the rate is typically not adjusted as the gas production rate declines. As production rates decrease over time, glycol units designed for the original production rates tend to over circulate causing emission increases without significant reduction in gas moisture content.

- **Using Electric Pumps:** The study determined that VOC emissions could be reduced by 67 percent by using electric pumps to move the glycol fluids. Typically, fluids are moved through the glycol dehydration and regeneration system by using the pressurized gas produced at the wellhead. VOC emissions occur when the gas is vented during the regenerator step.
- **Installing a Flash Vessel Separator:** The study determined that VOC emissions could be reduced by 10-40 percent by installing a flash vessel separator on dehydrator systems that do not already incorporate one.

The 2007 WRAP Phase II study "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II" (Bar-Ilan, et al. 2007) estimated that VOC and HAP emissions could be reduced by 98% through the use of VRUs. The US EPA, in AP-42, Chapter 13.5 (Industrial Flares), estimates that control of waste VOC via flaring would control VOC by a minimum of 98%. These technologies are also applicable for vents in dehydrator systems. VRUs also 'increase' oil and gas production by recovering hydrocarbons that would be lost and redirecting them for pipeline sale or onsite fuel supply.

3.8.3 Preferred Emission Estimation Approach

Dehydrator System Flash Vessels and Glycol Regenerator Vents: As a preferred method, ERG will use the basic methodology from the CENRAP study to generate estimated emissions from dehydrators. The calculation of emission factors will be based on gas composition and production data obtained from the survey or other available data, and the annual natural gas production by county will be obtained for the year 2008 from the TRC. Survey data will be used to estimate the percentage of dehydration systems using four control technologies (optimize flow rate, flash tanks, VRUs, and flares). GlyCalc will be used to develop emission factors for VOC, benzene, toluene, ethylbenzene, and xylene (BTEX). Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide.

Glycol Regenerator Boilers: Emission factors for glycol regenerator boilers will be based on survey data for the amount of fuel needed to regenerate the glycol given the glycol flow rates and average moisture content of the gas produced. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide.

The equations and methodology for estimating dehydrator-related emissions are discussed below. These equations assume that all gas requires dehydration, either in the field or at a central processing facility, that all dehydrators circulate glycol at the optimum rate, and that the standard dehydrator system does not incorporate a flash vessel.

The calculation methodology for dehydrator flash vessel and glycol regenerator vent emissions at the county level follows Equation 14:

$$E_{dehydrator,\ i,\ county\ j} = EF_{dehydrator,\ i,\ county\ j} \text{ x } P_{gas,\ county\ j} \text{ x } (1 + 0.5\ C_{flowrate} - 0.25\ C_{flashvessel} - 0.98\ C_{vru} - 0.98\ C_{flare}) \qquad \text{Equation (14)}$$

where:

$E_{dehydrator,\ i,\ county\ j}$ is the emissions of pollutant i from dehydrators in county j [tons/year]
$EF_{dehydrator,\ i,\ county\ j}$ is the emission factor for pollutant i from dehydrators in county j [tons/MSCF]
$P_{gas,\ county\ j}$ is the production of gas in county j [MSCF/year]
$C_{flowrate}$ is the fraction of gas production in county j without optimized dehydrator flow rate
$C_{flashvessel}$ is the fraction of gas production in county j with dehydrators equipped with flash tanks
C_{vru} is the fraction of gas production in county j controlled by VRUs
C_{flare} is the fraction of gas production in county j controlled by flares

A glycol regenerator boiler is essentially a heater and has similar emissions characteristics to typical combustion units. On-site gas is typically used as the fuel. Glycol regenerator boiler emission factors are developed using the process simulation software GlyCalc and AP-42 emission factors for heaters. The emission factor is developed in terms of the amount of heat needed to process one MSCF of produced gas, and is adjusted for the heat content of the on-site gas, as needed. The calculation methodology for glycol regenerator boilers at the county level follows Equation 15:

$$E_{regenerator\ boiler,\ i,\ county\ j} = EF_{regenerator\ boiler,\ i} \text{ x } P_{gas,\ county\ j} \qquad \text{Equation (15)}$$

where:

$E_{regenerator\ boiler,\ i,\ county\ j}$ is the emissions of pollutant i from glycol regenerator boilers in county j [tons/year]
$EF_{regenerator\ boiler,\ i}$ is the emission factor for pollutant i from a glycol regenerator boiler per unit production [tons/MSCF]
$P_{gas,\ county\ j}$ is the gas production [MSCF/year]

3.8.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level data on gas composition (VOC content and HAP speciation), typical configurations of dehydration system equipment (including glycol flow rates per MSCF of gas produced), and the GlyCalc software are required. ERG will collect data on the natural gas production per county using the most recently available database from the TRC, and will purchase the GlyCalc software directly from the vendor. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.9 Storage Tanks

Storage tanks are used in a variety of applications in the oil and gas industry. An oil and gas well may produce oil, natural gas, or a mixture of the two. When oil and gas are brought to the surface, the liquids produced may contain a mixture of liquid and gaseous organic compounds, nitrogen, carbon dioxide, water, sand, and other impurities. The mixture is typically passed through a three-phase separator, which allows the water, oil and gas to separate. The liquid oil and water components are then piped to storage tanks. If the well produces gas, it is possible that liquids may condense out of the gas as the pressure is decreased. The hydrocarbon liquid produced at gas wells is known as condensate. Oil and condensate are piped to storage tanks until they can be transported offsite. Tanks are typically vented to the atmosphere.

Oil and condensate storage tank emissions at wellhead and gathering sites are composed of flashing losses, working losses, and breathing losses. Flashing losses occur when a produced liquid (crude oil or condensate) with entrained gases experiences a pressure drop, as during the transfer of liquid hydrocarbons from a wellhead or separator to a storage tank. As the pressure on the liquid drops, some of the lighter compounds dissolved in the liquid are released or "flashed". Some compounds that are liquids at the initial pressure and temperature, change phase from a liquid to a gas and are also released or "flashed" from the liquid in the storage tank. Working losses occur when vapors are displaced from a tank during the filling and unloading cycles, and when the fluid is agitated during filling of the tank. Breathing losses (also called standing losses) occur due to the normal evaporation of liquid in a tank. Breathing losses are vapors that are produced in response to the daily temperature change.

3.9.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from oil and condensate storage tanks. The relevant sources reviewed are listed in Table 3.9.

Table 3.9 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Storage Tanks

Report Title	Geographic Coverage	Publication Date
Calculation of Flashing Losses/VOC Emissions from Hydrocarbon Storage Tanks (ODEQ, 2004)	All Regions	July, 2004
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II (Bar-Ilan, et al., 2007)	WRAP States	September, 2007
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Uinta Basin (Friesen, et al., 2009)	Uinta Basin, Utah	March , 2009

Table 3.9 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Storage Tanks (Cont.)

Report Title	Geographic Coverage	Publication Date
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin (Bar-Ilan, et al., 2009a)	Piceance Basin, Colorado	January, 2009
Development of Baseline 2006 Emissions from Oil and Gas Activity in the South San Juan Basin (Bar-Ilan, et al., 2009b)	San Juan Basin, New Mexico	November, 2009
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
Technical Supplement 6: Above Ground Liquid Storage Tanks (TCEQ, 2009a)	Texas	January 2009
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation (TCEQ, 2009b)	Texas	July, 2009
Flash Emissions Model Evaluation Quantifying Volatile Organic Compound Emissions from Upstream Oil and Gas Storage Tanks (TCEQ, 2009d)	Texas	October 2009
VOC Emissions From Oil And Condensate Storage Tanks (TERC, 2009)	East Texas	April, 2009
Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites (APDG 5942) (TCEQ, 2009c)	Texas	September, 2009

3.9.2 Emission Estimation Approaches

The reviewed literature provided both component-based and production-based approaches for estimating emissions from oil and condensate storage tanks. The three 2009 WRAP Phase III studies "Development of Baseline 2006 Emissions from Oil and Gas Activity in the San Juan Basin" (Bar-Ilan, et al., 2009b), "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Piceance Basin" (Bar Ilan, et al., 2009a), and "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Uinta Basin" (Friesen, et al., 2009) either used storage tank emission factors supplied by producers or calculated emission factors for storage tanks based on data provided by the producers. These emission factors were then used to directly calculate emissions based on production at each well site (Piceance Basin), or to derive weighted average emission factors for the basin that were then multiplied by basin-wide production to derive emission estimates (San Juan Basin, Uinta Basin).

The 2009 TERC study “VOC Emissions From Oil And Condensate Storage Tanks” (TERC, 2009) used data from the measured emissions from oil and condensate tank batteries to develop emission factors for the other oil and condensate storage tanks in the East Texas region.

The 2009 TCEQ study “Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation” (TCEQ, 2009b) compared data from directly measured emissions from 36 oil and condensate storage tank batteries to the emissions estimates generated using the HYSYS process simulator, the E&P Tank model, the Gas-to-Oil Ratio (GOR), the Vasquez-Beggs correlation, the GRI-HAPCalc program, the Valko-McCain correlation, the EC/R equation, and TANKS 4.09d.

The 2008 CENRAP study “Recommendations for Improvements to the CENRAP States’ Oil and Gas Emissions Inventories” (Bar-Ilan, et al., 2008) estimated emission factors for oil and condensate storage tanks using GRI-GLYCalc or HYSYS software, and these emission factors were multiplied by production figures for oil and condensate to develop emissions estimates. The 2009 TCEQ study “Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation” (TCEQ, 2009b), the 2009 TCEQ guidance “Technical Supplement 6: Above Ground Liquid Storage Tanks” (TCEQ, 2009a), and the 2009 TCEQ guide “Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites (APDG 5942)” (TCEQ, 2009c) recommend calculating working and breathing losses with EPA TANKS and calculating flashing losses from black oil systems and gas condensate systems using, in order of preference, direct measurement, process simulator models (HYSIM, HYSIS, WINSIM, or PROSIM), the E&P TANK program, GRI-HAPCalc, or the GOR method.

The 2007 TCEQ study used an emission factor developed for gas production in Wyoming, which was applied to oil and condensate production data for Texas.

The reviewed literature also addressed the effect of storage tank control technologies on emissions. The 2007 WRAP Phase II study “WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II” (Bar-Ilan, et al. 2007) estimated that VOC and HAP emissions could be reduced by 98% through the use of VRUs. VRUs also ‘increase’ oil and gas production by recovering hydrocarbons that would be lost and redirecting them for pipeline sale or onsite fuel supply. The US EPA, in AP-42, Chapter 13.5 (Industrial Flares), estimates that control of waste VOC via flaring would control VOC by a minimum of 98%.

3.9.3 Preferred Emission Estimation Approach

ERG proposes a two tiered approach to developing regional emission estimates. ERG will use the methodology and emission factor data developed in the 2009 TERC to develop emission estimates for oil and condensate storage tanks in the East Texas Shale region. ERG will use this same methodology in other regions of Texas for which adequate existing direct measurement data are available. For other regions of Texas, ERG will use the methodology recommended in the 2009 TCEQ study, the 2009 TCEQ guidance, and the 2009 TCEQ APDG 5942. Specifically, we anticipate that working and breathing losses will be calculated with EPA TANKS, and flashing losses will be calculated using process simulator models, the E&P TANK program, GRI-HAPCalc, or the GOR method, using the average VOC content of wellhead gas, obtained from a gas composition analyses, the API gravity of oil, and the gas-oil ratio, as data is available.

Emission factors developed using these approaches will be assigned to the counties within their respective regions and will be multiplied by county-specific production data obtained from the TRC to derive county-specific emission estimates. Data on operating temperature and pressure will be collected via survey and emissions will be adjusted for the appropriate operating parameters.
The calculation methodology for oil storage tank emissions at the county level follows Equation 16:

$$E_{oil\ tank,\ i,\ county\ j} = EF_{oil,\ i,\ county\ j} \times P_{oil,\ county\ j} \times (1 - 0.98\ C_{vru} - 0.95\ C_{flare}) \qquad \text{Equation (16)}$$

where:

$E_{oil\ tank,\ i,\ county\ j}$ is the emissions of pollutant i from oil storage tanks in county j [tons/year]
$EF_{oil,\ i,\ county\ j}$ is the emission factor for pollutant i from oil storage tanks in county j [tons/MSCF]
$P_{oil,\ county\ j}$ is the production of oil in county j [MSCF/year]
C_{vru} is the fraction of oil production in county j controlled by VRUs
C_{flare} is the fraction of oil production in county j controlled by flares

The calculation methodology for condensate storage tank emissions at the county level follows Equation 17:

$$E_{condensate\ tank,\ i,\ county\ j} = EF_{condensate,\ i,\ county\ j} \times P_{condensate,\ county\ j} \times (1 - 0.98\ C_{vru} - 0.95\ C_{flare}) \qquad \text{Equation (17)}$$

where:

$E_{condensate\ tank,\ i,\ county\ j}$ is the emissions of pollutant i from oil storage tanks in county j [tons/year]
$EF_{condensate,\ i,\ county\ j}$ is the emission factor for pollutant i from oil storage tanks in county j [tons/MSCF]
$P_{condensate,\ county\ j}$ is the production of oil in county j [MSCF/year]
C_{vru} is the fraction of condensate production in county j controlled by VRUs
C_{flare} is the fraction of condensate production in county j controlled by flares

Emission factors, $EF_{oil,\ i,\ county\ j}$, $EF_{condensate,\ i,\ county\ j}$:
The 2009 TERC study developed emission factors for oil and condensate storage tanks in the East Texas region. ERG will use these emission factors in developing emissions estimates for the counties covered by these studies. For the remainder of Texas, ERG will attempt to obtain county-level data on the properties of oil and condensate produced to develop emission factors for oil and condensate storage tanks using process simulation models or other emissions estimation models as outlined above. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide.

Production of oil and condensate $P_{oil, county j}$, $P_{condensate, county j}$
ERG will obtain county level data on the production of oil and condensate from the TRC.

Fraction of storage tanks controlled by flares, C_{flare} and the fraction of storage tanks controlled by VRUs, C_{vru}:
ERG will attempt to obtain estimates for the number of storage tanks controlled by flares or VRUs either by conducting a survey of oil and gas producers, or from existing data from the TRC. Depending on the amount of data collected, averages may be determined at the county level, the TRC District level, the basin level, or state-wide.

3.9.4 Data Needs

In order to implement the preferred emission estimation approach, county-level data on monthly oil and condensate production data, monthly average temperature data, the frequency of oil and condensate tank unloading operations, and oil and gas composition/speciation profiles are needed. ERG will collect survey data on the number, size, configuration and usage of tanks at oil wells and gas wells, along with production data matched to those sites, so that averages for tank volume relative to production rate can be determined. ERG will collect data on oil and condensate production data using the most recently available database from the TRC. ERG will attempt to collect all other data items by conducting a survey of oil and gas producers owning active wells in the Texas counties covered in this emissions inventory development effort.

3.10 Oil and Condensate Loading Racks

Oil and condensate stored in field storage tanks is transferred to trucks and railcars and shipped to refineries for further processing. Fugitive VOC emissions are released from these loading processes as the vapors in the receiving vessel are displaced by the liquids from the storage tanks. These vapors are normally vented to the atmosphere.

3.10.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from oil and condensate loading racks. The relevant sources reviewed are listed in Table 3.10.

Table 3.10 Oil and Gas Exploration Emissions Studies

Report Title	Geographic Coverage	Publication Date
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II (Bar-Ilan, et al. 2007)	Western States	September, 2007
Development of Baseline 2006 Emissions from Oil and Gas Activity in the South San Juan Basin (Bar-Ilan, et al., 2009b)	New Mexico	November, 2009

3.10.2 Emission Estimation Approaches

The August 2007 TCEQ report "Emissions from Oil and Gas Production Facilities" (TCEQ, 2007) and the November 2009 report "Development of Baseline 2006 Emissions from Oil and Gas Activity in the South San Juan Basin" (Bar-Ilan, et al., 2009b) included a production-based emissions methodology for oil and condensate loading. Both of these studies estimated uncontrolled VOC emissions from oil and condensate loading using the AP-42 loading equation.

In the 2007 TCEQ study, the true vapor pressure of oil and condensate was determined by using average temperature data for each county in Texas and temperature-dependent vapor pressures of crude oil from AP-42. Temperature data from 87 weather stations throughout Texas were obtained and isotherms were developed to estimate average annual temperatures for each county in Texas. These temperatures determined both the true vapor pressure using AP-42 data and the average temperature of the bulk liquid (T). The molecular weight of tank vapors was assumed constant and equal to AP-42 data for crude oil (50 lb/lb-mole) and gasoline (RVP 7) (68 lb/lb-mole) at 60 degrees F for oil and condensate, respectively. The gasoline value was used for condensate since no specific number for condensate was available. The type of loading operation was assumed to be submerged loading with a dedicated vapor balance.

The AP-42 equation to calculate temperature-dependent emission factors for loadout losses generates an emission factor based on the amount of liquid loaded. The calculated emission factors were applied to the amount of oil and condensate produced in each county, which was obtained from data provided by the TRC.

The reviewed literature also addressed the effect of storage tank control technologies on emissions. These technologies could be adapted to control emissions from storage tank unloading. The 2007 WRAP Phase II study "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II" (Bar-Ilan, et al. 2007) estimated that VOC and HAP emissions could be reduced by 98% through the use of VRUs. The US EPA, in AP-42, Chapter 13.5 (Industrial Flares), estimates that control of waste VOC via flaring would control VOC by a minimum of 98%.

3.10.3 Preferred Emission Estimation Approach

ERG will use the methodology in the 2007 TCEQ study and the 2009 WRAP Phase III study. AP-42 emission factors for loading losses will be calculated at the county level. These emission factors will be multiplied by county-specific production data obtained from the TRC to derive county-specific emission estimates. This methodology requires oil and condensate production data, data on the composition and RVP of the oil and condensate produced, and monthly temperature data for the counties in which the oil and condensate are produced. Survey data will be gathered on the number of sites in the county that use VRUs or flares to control loading emissions. These data will be used to account for emissions controlled by VRUs or flares.

The AP-42 equation to calculate loading emission factors is shown in Equation 18:

$$LL_{oil,\ condensate,\ county\ j} = 12.46 \text{ x } S \text{ x } P \text{ x } M \,/\, T_{county\ j} \qquad \text{Equation (18)}$$

Where:

$LL_{oil,\ condensate,\ county\ j}$ is the loading loss [lb/1,000 gal of liquid loaded] for county j
S is Saturation factor (based on type of loading operation)
P is True vapor pressure of liquid loaded [psia]
M is Molecular weight of tank vapors [lb/lb-mole]
$T_{county\ j}$ is Temperature of bulk liquid loaded [^{o}R] for county j

The AP-42 equation to calculate temperature-dependent emission factors for loadout losses generates an emission factor based on the amount of liquid loaded. Truck or railcar loading emissions will then be calculated by multiplying the emission factor by county-level production figures for oil and condensate production, as shown in Equation 19:

$$E_{loading,\ county\ j} = LL_{oil,\ condensate,\ county\ j} \text{ x } P_{oil,\ condensate,\ county\ j} \text{ x 42 gal/bbl x 1 ton/2,000 lbs x } (1 - 0.98\ C_{vru} - 0.98\ C_{flare}) \quad \text{Equation (19)}$$

Where:

$E_{loading,\ county\ j}$ is the emissions from oil or condensate truck loading for county j [ton/year]
$LL_{oil,\ condensate,\ county\ j}$ is the emission factor for oil or condensate loading loss for county j [lb/1,000gal]
$P_{oil,\ condensate,\ county}j$ is oil or condensate production for county j [bbl/year]
C_{vru} is the fraction of loading in county j controlled by VRUs
C_{flare} is the fraction of loading in county j controlled by flares

3.10.4 Data Needs

In order to implement the preferred emissions estimation approach, county-level oil and condensate production data on a monthly basis, loading type, vapor pressure data for oil and condensate, molecular weight of tank vapors, and monthly average temperature data for each county is needed. ERG will collect county-level oil and condensate production data using the most recently available database from the TRC. ERG will attempt to obtain the other data needed to apply this methodology through the survey. If survey data is unavailable, default data may be used as described above for the 2007 TCEQ study. The 2007 TCEQ data can also be used as a QA check on the reasonableness of the survey results.

3.11 Compressor Engines

Spark-ignited internal combustion engines are normally used to drive gas field compressors. The compressors are used to boost the pressure of well-head natural gas so that it can be injected into higher pressure gathering lines. These compressor engines burn well-head natural gas and can represent a significant NO_x area emissions source category as they generally operate 8,760 hours per year with minimum down-time. For this project, in addition to criteria pollutant emissions, formaldehyde emissions from compressor engines will be estimated. Formaldehyde is formed as a by-product of the combustion process.

3.11.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from compressor engines. The relevant sources reviewed are listed in Table 3.11.

Table 3.11 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Compressor Engines

Report Title	Geographic Coverage	Publication Date
Tyler/Longview/Marshall Flexible Attainment Region Emission Inventory of Ozone Precursors VOC, NOx and CO (Pollution Solutions, 2005)	Tyler, Longview, Marshall area, Texas	February, 2005
Natural Gas Compressor Engine Survey and Engine NOx Emissions at Gas Production Facilities (HARC, 2005)	Eastern Portion of Texas	August, 2005
Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico (Pollack, et al., 2006)	San Juan and Rio Arriba Counties, New Mexico	August, 2006
Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities (Burklin and Heaney, 2006)	Eastern Portion of Texas	October, 2006
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
Special Study Relating to Oil and Gas Production: 2005 and 2007 Emissions from Compressor Engines with Consideration for Load Factor (Pollution Solutions, 2008)	Tyler, Longview, Marshall area, Texas	August, 2008
Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventories (Bar-Ilan, et al., 2008)	CENRAP States	November, 2008
2008 Southeast Texas Compressor Engines and Dehydrators Survey (TCEQ, 2009e)	Southeast Texas	Presentation May, 2009
Development of Emissions Inventories for Natural Gas Exploration and Production Activity in the Haynesville Shale (Grant, et al., 2009)	Northeast Texas and Northwest Louisiana	August, 2009

3.11.2 Emission estimation approaches

Of the studies reviewed, the majority take a similar approach in determining emissions from compressor engines at oil and gas production facilities. These studies typically apply a county specific emission factor (developed through various survey data) to natural gas production by county. The specific methodology is discussed in Section 3.11.3.

It should be noted that the CENRAP 2008 report varies from this approach in that it recommends using well count as a surrogate for scaling wellhead compressor emissions to the basin level. The report states that gas production estimates may underestimate the number of wellhead compressors in use. County-level emissions estimates were then derived by allocating basin total wellhead compressor engine emissions to the county level by the fraction of total basin wells in each county.

3.11.3 Preferred emission estimation approach

As a preferred method to estimate emissions from natural gas compressor engines, ERG will use annual natural gas production by county along with survey-generated county-level emission factors to determine emissions from compressor engines at oil and gas production facilities. The annual natural gas production by county will be obtained for the year 2008 from the TRC.

County-level emission factors will be calculated using the methodology from the study "Natural Gas Compressor Engine Survey and Engine NO_X Emissions at Gas Production Facilities" conducted by ERG for the Houston Advanced Research Council (HARC) to generate emission factors from compressor engines at oil and gas production facilities (HARC, 2005). The HARC 2005 report was updated in 2006 to include more engine size categories and to add the year 2000 to the previous inventory; however, these updates did not change the calculation methodology used in the original 2005 report.

County-level emission factors will be calculated Equation (19) as provided in the HARC study reports:

$$EF_{ijk} = F_{1i} \times F_{2j} \times C_i \times H_j \times EF_{jk} \times 1/2000 \qquad \text{Equation (19)}$$

Where:

- EF_{ijk} is the emission factor for county i, for engine type j, and pollutant k [tons/MSCF]
- F_{1i} is the fraction of wells requiring compression in county i
- F_{2j} is the fraction of compression load represented by engines of type j
- C_i is the compression requirements for county i [hp-hr/MSCF]
- H_j is the brake specific fuel consumption for engine type j [MMBtu/hp-hr]
- EF_{jk} is the emission factor for engine type j, and pollutant k [lb/MMBtu]

The data needed to implement this approach is discussed below.

Fraction of wells requiring compression in county i, F_{1i}:
The HARC studies (HARC, 2005 and 2006) assumed the fraction of wells requiring compression is equal to the fraction of wells greater than one year old. As 2008 is the base year for this study and was an unusually active year in Texas for well drilling, ERG will attempt to verify this assumption by contacting experts in the field by phone as well as through a survey questionnaire. Although the fraction of wells greater than one year old was relatively constant in the three districts examined by the HARC studies, ERG will re-calculate an average fraction across the entire state using data from all twelve TRC districts for 2008. The number of wells completed each year and the total number of operating wells by district are available from the TRC.

Fraction of compression load represented by engines of type j, F_{2j}:
While the initial report (HARC, 2005) focused on engines less than 500 horsepower (hp), the follow-up report (HARC, 2006) included engines greater than 500 hp and also provided a more detailed breakdown of engines less than 500 hp. ERG will attempt to update the distribution of engine types through a new survey questionnaire. In addition, ERG will combine engine data from the two 2007 TCEQ engine surveys conducted on the counties located in the Dallas -Forth Worth (D-FW) metropolitan area and Southeast Texas. These TCEQ surveys were completed as efforts to amend the state clean air plan for ozone. Engine operators reported engine counts, engine sizes, NO_X emissions, and other data to TCEQ. If insufficient data are available through the D-FW and Southeast Texas surveys, ERG may default to the distribution of engine types presented in the follow-up HARC report and TCEQ surveys to estimate the fractions of various engine types in attainment and nonattainment areas of Texas.

Compression Requirements for county i, C_i:
A compressor's operating behavior is generally dependent on the relationship between pressure ratio and volume or mass flow rate. In particular, the operating behavior for a compressor engine located at an oil and gas well is based on the compressor suction and discharge pressures required to convey the natural gas from the well head to the gathering lines. These pressures, or the compression ratio, along with the natural gas flow-rate through the compressor, define the engine load in terms of the amount of mechanical work that is required to compress the natural gas produced by the well. This mechanical work (hp-hr) is directly proportional to the volume of fuel (MSCF) that must be burned by the compressor engine and the relationship is termed a *compression requirement* (hp-hr/MSCF). Special compressor calculators can be used to convert inlet and outlet pressures into *compression requirements* which can then be used to determine emissions created by compressor engines. Because of this direct relationship of mechanical work to volume of fuel burned, one would expect a 100 Hp engine to burn almost an equal amount of fuel as two (2) 50 Hp engines when compressing the same volume of natural gas produced by the same well. Therefore, it is not necessary to know the specific numbers of engines, or their individual sizes when calculating emissions from compressors at the county level.

In spite of this observable fact, all natural gas compressors have a maximum rating and most of them deliver less natural gas than their maximum rating. In a 2002 emissions inventory (Pollution Solutions, 2005) entitled "Tyler/Longview/Marshall Flexible Attainment Region Emission Inventory", the author developed a *compression requirement* (hp-day/MSCF) through survey data assuming the compressor engines were operating under full load or maximum installed horsepower. This assumption caused an overestimation of the amount of fuel that was consumed by the compressor engines and consequently overestimated the amount of emissions from these engines. A more recent study by Pollution Solutions (2008) entitled "2005 and 2007 Compressor Engine Emissions and Load Factors Report" determined average load factors for three engine categories, all of which were less than 100%. For engines less than 240 hp, the load factor was 70%. For engines between 240-500 hp, the load factor was 69%. For engines greater than 500 hp, the load factor was 58%. These engine load factors were applied to the previous study (Pollution Solutions, 2005) in order to determine more accurate emissions estimates for compressor engines located in Panola County as well as the five NETAC counties.

The 2005 HARC report developed compression requirements ranging between 3.1 and 3.5 Hp-hr/MSCF for three distinct districts in eastern Texas, including one attainment area and two nonattainment areas (Houston and Dallas) by obtaining typical well pressures and gathering line pressures through a field study. The engines in this particular field survey were operated at loads ranging from about 10% to 70% of full load, and averaged 40% load. Additionally, compression requirements that can be deduced from the 2008 Pollution Solutions study are relatively in-line with the compression requirements used in the 2005 HARC report. More specifically, the 191 Hp-day/MSCF compression requirement used in the 2005 Pollutions Solutions study, when adjusted for the load factors from the 2008 Pollutions Solutions study, yield *compression requirements* between 4.5 to 5.5 Hp-hr/MSCF. Additionally, TCEQ determined through a 2007 TCEQ engine survey (conducted on the counties located in the D-FW metropolitan area) a *compression requirement* of 226 Hp-day/MMcf for area source compressor engines outside the D-FW metropolitan area. This value equates to approximately 5.4 Hp-hr/MSCF which is also in agreement with previous studies mentioned.

ERG will attempt to develop 2008 compression requirements through a new survey questionnaire that would aim to collect typical well pressures and gathering line pressures, as well as engine load factors. As mentioned previously, the compression requirements developed for the 2005 HARC study, the 2008 Pollution Solutions study, and the 2007 TCEQ engine D-FW metropolitan survey were all relatively consistent. ERG may default to and apply an average of these factors to the entire state in both attainment and nonattainment areas if insufficient data is obtained through the survey effort.

<u>Brake specific fuel consumption for engine type j, H_j:</u>
The HARC studies (HARC, 2005 and 2006) determined brake specific fuel consumption for the most common engine model of each engine category using engine model distributions provided by engine leasing companies. ERG will develop updated representative engine models using data gathered through a survey questionnaire. In addition, ERG will use the engine data from the two 2007 TCEQ engine surveys conducted on the counties located in the D-FW metropolitan area and Southeast Texas, and may use the 2005 and 2006 HARC data as well.

<u>Emission factor for engine type j, and pollutant k, EF_{jk}:</u>
As noted in the 2008 CENRAP study, there are two distinct types of compressor engines used to boost the pressure of well-head natural gas: “rich-burn” engines that are characterized by NO_x emissions factors in the range of approximately 10 – 20 g/bhp-hr; and “lean-burn” engines that are characterized by NO_x emissions factors in the range of approximately 1.0 – 5.0 g/bhp-hr. The

exact NO_x emissions factors depend on the horsepower, make and model, and model year of the engine, and whether the engine has been converted from a rich-burn to a lean-burn engine.

Many of the compressor engine emission factors used in the 2008 CENRAP study came from a 2006 study entitled: "Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico" (Pollack, et al., 2006). This particular study contained an extensive database of emissions factors for a range of well-head compressor engine makes and models. From this database, average rich-burn and lean-burn engine emissions factors for NO_x, VOC, CO, and SO_2 were derived. PM_{10}, CO_2, and CH_4 emission factors were obtained from AP-42. It should be noted that all pollutant and engine-specific emission factors used in the 2005/2006 HARC studies were taken from AP-42.

For this study, ERG will attempt to develop improved emission factors (especially for NO_x and formaldehyde emissions) using data gathered through a survey questionnaire in order to estimate pollutant emissions from each engine type based on the county-by-county breakdown of engine use described above. In addition to new survey data, ERG will use the engine data from the two 2007 TCEQ engine surveys conducted on the counties located in the D-FW metropolitan area and Southeast Texas; as well as the data from the 2006 New Mexico study. If insufficient data is collected through the survey effort, ERG may default to and apply the average rich-burn and lean-burn engine emissions factors used in the 2006 New Mexico study, or AP-42 emission factors.

ERG has not found any studies using a different formaldehyde emission factor than provided in EPA's AP-42 document (July 2000) entitled "Natural Gas-fired Reciprocating Engines". AP-42 presents Formaldehyde emission factors for 2-stroke lean burn engines, 4-stroke lean burn engines, and 4-stroke rich burn engines. All the AP-42 formaldehyde emission factors have an "A" rating.

3.11.4 Data Needs

In order to implement the preferred emission estimation approach, the gas production in each county is needed. ERG will collect data on throughput per county using the most recently available database from the TRC. This activity data when applied to the different factors mentioned in Section 3.11.3 above, will allow ERG to estimate county-level emissions from compressor engines.

3.12 Turbines

Turbines are used in the oil and gas industry to compress gas or to generate electricity. In the gas industry they tend to be used in processing and transmission rather than gathering applications (CAPP, 2004). Compressors driven by turbines may be found at midstream oil and gas facilities such as large pipeline compressor stations, gas storage facilities, or gas processing plants. Turbines may also be utilized in some smaller upstream applications to assist in the transfer of gas produced in the field from multiple or individual well sites or gas gathering plants to midstream facilities. However, some of these applications (at the well or gas gathering plant level) are usually handled by reciprocating internal combustion engines, which are covered in

Section 3.11 of this memo. Most midstream facilities utilizing natural gas-fired turbines are assumed to be permitted and included in the inventory as major point sources. Turbines used in the oil and gas industry burn natural gas and can represent a significant source of NO_x emissions, in addition to other combustion-related pollutants.

In remote locations such as offshore platforms or oil and gas fields where electricity off the grid is not readily available, gas turbines may be used in a combined heat and power (CHP) application to drive generators for electricity and to provide heat in buildings and crew quarters.

3.12.1 Literature Review

ERG conducted a literature review to obtain information on established methodologies to estimate the atmospheric release of pollutants from turbines. The relevant sources reviewed are listed in Table 3.12.

Table 3.12 Existing Oil and Gas Exploration Emissions Studies Containing Methodologies for Turbines

Report Title	Geographic Coverage	Publication Date
Emissions from Oil and Gas Production Facilities (TCEQ, 2007)	Texas	August, 2007
Development of Baseline 2006 Emissions from Oil and Gas Activity in the Uinta Basin (Friesen, et al., 2009)	Uinta Basin, Utah	March , 2009

3.12.2 Emission estimation approaches

The reviewed literature did not provide any sources that explicitly included gas-fired turbines as an area source emissions source.

The study “Development of baseline 2006 Emissions From Oil and Gas Activity in the Unita Basin” (Friesen, et al., 2009) included one compressor station that was defined as a turbine as part of the point source inventory. The data for this point source was provided directly by the State of Utah.

The study “Emissions from Oil and Gas Production Facilities” (TCEQ, 2007) included emission from turbines located at offshore platforms as obtained from the Minerals Management Service (MMS). The study did not estimate emissions from onshore turbines.

3.12.3 Preferred emission estimation approach

At this point, it is unknown whether turbines will be found at locations other than point sources already included in the State of Texas Air Reporting System (STARS) emissions inventory. There are no existing studies that present approaches for estimating area sources emissions from turbines used in oil and gas upstream production sources, but there are AP-42 emission factors that could be used if it is discovered that there are turbines not counted in the point source inventory.

3.12.4 Data Needs

As part of the survey efforts, ERG will include questions pertaining to turbine usage in gas field applications at the well level and at gas gathering and processing stations. As any smaller turbines (those not already included in the point source inventory) would be used for the same purposes as compressor engines, the target recipients of the survey would be identical. Based on the findings of the HARC "Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities" study (HARC, 2006), there are very few engines used in gas field compressor applications approaching the size of the smallest turbines (approximately 1,500 hp).

ERG will coordinate inclusion of turbines in this area source inventory with TCEQ if it is determined that there are turbines unaccounted for in the point source inventory.

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APPENDIX A

LIST OF ACRONYMS/ABBREVIATIONS

API	American Petroleum Institute
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CAPP	Canadian Association of Petroleum Producers
CenRAP	Central States Regional Air Partnership
CO	Carbon Monoxide
DOE	U.S. Department of Energy
ERG	Eastern Research Group, Inc.
GOR	Gas-to-Oil Ratio
GPA	Gas Processors Association
GRI	Gas Research Institute
HAP	Hazardous Air Pollutant
HARC	Houston Advanced Research Center
hp	Horsepower
H_2S	Hydrogen Sulfide
IPMAS	Independent Petroleum Association of Mountain States
LPG	Liquefied Petroleum Gas
MMS	Minerals Management Service
MMSCF	Million Standard Cubic Feet
MMSCFD	Million Standard Cubic Feet Per Day
MSCF	Thousand Standard Cubic Feet
MW	Molecular Weight
NETAC	Northeast Texas Air Care
NIF	National Emissions Inventory Input Format
NOx	Nitrogen Oxides
PM_{10}	Particulate Matter that has particle diameter less than 10 micrometers
$PM_{2.5}$	Particulate Matter that has particle diameter less than 2.5 micrometers
QA	Quality Assurance
SCC	Source Classification Code
SCF	Standard Cubic Feet
SO_2	Sulfur Dioxide
STARS	State of Texas Air Reporting System
STP	Standard Temperature and Pressure
TCEQ	Texas Commission on Environmental Quality
TexAER	Texas Air Emissions Repository
TRC	Texas Railroad Commission
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit
WRAP	Western Regional Air Partnership
WYDEQ	Wyoming Department of Environmental Quality

Appendix B – Task 3 Memorandum

TECHNICAL MEMORANDUM

Date: July 9, 2010

To: Martha Maldonado
Project Representative
Texas Commission on Environmental Quality (TCEQ)

From: Mike Pring, Eastern Research Group, Inc. (ERG)
Daryl Hudson (ERG)
Jason Renzaglia (ERG)
Brandon Smith (ERG)
Stephen Treimel (ERG)

Re: Oil and Gas Sources Inventory – Final Technical Memorandum for Task 3
TCEQ Contract No. 582-7-84003, Work Order No. 582-7-84003-FY10-26

1.0 Introduction

The purpose of this Work Order is to develop a 2008 base year air emissions inventory from upstream onshore oil and gas production sites for select counties in Texas. The inventory will address area source criteria pollutant emissions of volatile organic compounds (VOC), nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and sulfur dioxide (SO_2); and certain toxic pollutant emissions such as formaldehyde from compressor engines, and benzene, toluene, ethylbenzene, and xylene from dehydrators. In addition to compiling the emissions inventory, other goals of this Work Order are to identify the emission source types operating at oil and gas production sites, identify the best emissions determination methodology for each emission source type, develop a methodology for estimating emissions from oil and gas production sites based on the oil and gas produced at the county level, and identify the producers of oil and gas for each county.

This Work Order builds on two previous studies ERG conducted for TCEQ to estimate emissions from oil and gas exploration and production activities. The first, implemented in 2007, focused on compiling a state-wide emissions inventory (including both onshore and offshore sources) for oil and gas exploration and production for a 2005 base year (ERG, 2007). The second study, conducted in 2009 for a 2008 base year, focused only on emissions from onshore oil and gas well drilling rig engines (ERG, 2009). Both of these studies included emission estimates for every county in Texas. In contrast, this current study will only address onshore area sources (those not included in the Texas point source inventory), and does not address drilling rig engines. TCEQ is also currently developing an emissions inventory for offshore oil and gas platforms under TCEQ Work Order No. 582-07-84003-FY10-25.

The onshore area source project is divided into four primary technical work tasks:

- Identification and review of existing studies pertaining to estimating emissions from oil and gas production sites and recommendation of an emission estimation approach for each identified source type;
- Identification of oil and gas well operators and preparation of draft survey materials, including obtaining data from existing studies and databases;
- Development of a methodology to estimate county-level emissions from each identified source type; and
- Development of a 2008 base year emissions inventory, including collection of activity and emissions data (as available), the preparation of emissions inventory calculation spreadsheets (including activity data and emission factors) and documentation of data, procedures, and results in a final project report. The final emissions inventory will be compiled into National Emissions Inventory Input Format (NIF) 3.0 text files for import into Texas Air Emissions Repository (TexAER).

The purpose of this memo is to document the methodology ERG will use to identify the owners and/or operators of oil and gas production sites, and to provide TCEQ with draft survey materials. Additionally, the methodology used to develop the draft survey materials are provided. In the project Work Plan, this work is referred to as Task 3.

This discussion begins by presenting the references and datasets that were used to identify oil and gas production sites owners and operators in Section 2.0. Section 3.0 presents example draft survey forms, the process used to develop these, with the forms and instructions for each source type provided in Attachment B.

County-level, area source emission estimates will be developed based on county-level oil and gas production data (total oil and gas produced in each county in 2008).

2.0 Identification of Oil and Gas Owners and Operators

This task targets identification of Oil and Gas Area Source operators who were active in Texas in 2008. A list of candidate owners and operators were obtained from multiple sources as follows:

- Texas Railroad Commission (RRC) and RigData® - ERG obtained data from the RRC for all oil and gas wells drilled in Texas in 2008. This database contains over 18,500 records for wells where drilling occurred in 2008. In addition, ERG obtained the RigData® database (a commercial database) in 2009 as part of the "Drilling Rig Emission Inventory for the State of Texas" project conducted for TCEQ. In addition to drilling contractor data, this database also contains owner and operator contact information (Company Name, Company Contact Name, and Company Contact Mailing Address) for over 24,000 wells. The combined data for these 2 datasets is included in Attachment A as "Drilling Data 2008 Contact Directory.xls".
- TCEQ Permit Data – TCEQ provided contact information for approximately 9,000 regulated entities registered with TCEQ pursuant to Standard Permit pursuant to 116.620 (Installation and/or Modification of Oil and Gas Facilities). This database contains

owner and operator contact information (Company Name, Company Contact Name, Company Contact Mailing Address, Company Contact Title, and Company Contact E-mail address for some sources). It is assumed that many of these sources are not currently required to report their air emissions to TCEQ under TAC 101.10(a)(1-3). This data is included in Attachment A as “Standard Permit 116.620 Contact Directory.xls”.

- Texas Railroad Commission (RRC) Oil & Gas Directory - Operator Contact Information – This data was obtained directly from the RRC and includes a listing of entities registered with the Commission's Oil and Gas Division by name, including address and telephone number. The listing includes all operators with Active status on Commission organization records, as well as those with "Delinquent" status (indicating that they still have activity, but have not updated their organizational registration). The listing does not include those with "Inactive" status (indicating no activity and no current registration). This data was obtained from (http://www.rrc.state.tx.us/data/operators/ogdirectory/index.php) on April 28, 2010 and is included in Attachment A as “TRC Oil and Gas Contact Directory.xls”.

These databases were imported into MS Access for easy querying for duplicates and to QA addresses and contact information. The final datasets of contact information are included in Attachment A.

3.0 Survey Forms

As TCEQ may wish to conduct a state-wide survey of oil and gas owners and operators in the future in order to refine the emissions inventory, survey forms were prepared for Artificial Lift Engines, Compressor Engines, Dehydrators, Equipment Leaks, Heaters, Loading Racks, Pneumatic Devices, Storage Tanks, Well Blowdowns, and Well Completions. These forms were structured such that the information needed to develop more highly-refined emissions estimates for each source category (at a county-level, using area source approaches) would be obtained. While obtaining the needed data, other goals in the development of these forms was to make them as straightforward as possible, to make them universally accessible (through the use of widely used software found in MS-Office), and to make them consistent with the format and nomenclature used in TCEQ’s current Barnett Shale study. TCEQ comments on the draft survey materials have been incorporated into the final survey materials provided herein.

Attachment B presents final survey forms for Artificial Lift Engines, Compressor Engines, Dehydrators, Equipment Leaks, Heaters, Loading Racks, Pneumatic Devices, Storage Tanks, Well Blowdowns, and Well Completions.

ATTACHMENT A

(See files "Standard Permit 116.620 Contact Directory.xls", "TRC Oil and Gas Contact Directory.xls", and "Drilling Data 2008 Contact Directory.xls")

ATTACHMENT B

Draft Survey Packages

(See files “Artificial Lift Engine Survey.xls”, “Compressor Engine Survey.xls”, “Dehydrator Survey.xls”, “Equipment Leaks Survey.xls”, “Heater Survey.xls”, “Loading Rack Survey.xls”, “Pneumatic Device Survey.xls”, “Storage Tank Survey.xls”, “Well Blowdown Survey.xls”, and “Well Completion Survey.xls”)

Appendix C - VOC and PM HAP Speciation Data

Appendix C. HAP Factors

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Pump Jack	Natural Gas	VOC	0.11259434	lb/MMBtu		
Pump Jack	Natural Gas	Acetaldehyde	2.79E-03	lb/MMBtu	2.48E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Acrolein	2.63E-03	lb/MMBtu	2.34E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Benzene	1.58E-03	lb/MMBtu	1.40E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	1,3-Butadiene	6.63E-04	lb/MMBtu	5.89E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Carbon Tetrachloride*	1.77E-05	lb/MMBtu	1.57E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Chlorobenzene*	1.29E-05	lb/MMBtu	1.15E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Chloroform*	1.37E-05	lb/MMBtu	1.22E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Dichlorobenzene	1.20E-03	lb/MMBtu	1.07E+00	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	1,3-Dichloropropene*	1.27E-05	lb/MMBtu	1.13E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	7,12-Dimethylbenz(a)anthracene*	1.60E-05	lb/MMBtu	1.42E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Ethylbenzene*	2.48E-05	lb/MMBtu	2.20E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Ethylene Dibromide*	2.13E-05	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Formaldehyde	2.05E-02	lb/MMBtu	1.82E+01	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Methanol	3.06E-03	lb/MMBtu	2.72E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Methylene Chloride	4.12E-05	lb/MMBtu	3.66E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	2-Methylnaphthalene	2.40E-05	lb/MMBtu	2.13E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	3-Methylchloranthrene*	1.80E-06	lb/MMBtu	1.60E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Naphthalene*	9.71E-05	lb/MMBtu	8.62E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Propylene	0.016842105	lb/MMBtu	1.50E+01	Air Resources Board. California Environmental Protection Agency. http://www.arb.ca.gov/app/emsinv/catef_form.html
Pump Jack	Natural Gas	Styrene*	1.19E-05	lb/MMBtu	1.06E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	1,1,2,2-Tetrachloroethane	2.53E-05	lb/MMBtu	2.25E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Toluene	5.58E-04	lb/MMBtu	4.96E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	1,1,2-Trichloroethane*	1.53E-05	lb/MMBtu	1.36E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Vinyl Chloride*	7.18E-06	lb/MMBtu	6.38E-03	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	Xylenes (isomers and mixture)	1.95E-04	lb/MMBtu	1.73E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Pump Jack	Natural Gas	o-Xylenes			0.01	EPA Speciate 4.2 Database
Pump Jack	Natural Gas	m-Xylenes			0.01	EPA Speciate 4.2 Database

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Pump Jack	Natural Gas	PM	7.70E-04	lb/MMBtu		
Pump Jack	Natural Gas	Acenaphthene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Acenaphthylene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Anthracene*	2.40E-06	lb/MMBtu	3.12E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Benz(a)anthracene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Benzo(a)pyrene*	1.20E-06	lb/MMBtu	1.56E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Benzo(b)fluoranthene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Benzo(g,h,i)perylene*	1.20E-06	lb/MMBtu	1.56E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Benzo(k)fluoranthene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Chrysene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Dibenzo(a,h)anthracene*	1.20E-06	lb/MMBtu	1.56E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Fluoranthene	3.00E-06	lb/MMBtu	3.90E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Fluorene	2.80E-06	lb/MMBtu	3.64E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Indeno(1,2,3-cd_pyrene*	1.80E-06	lb/MMBtu	2.34E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Phenanathrene	1.75E-05	lb/MMBtu	2.27E+00	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Pump Jack	Natural Gas	Pyrene	5.00E-06	lb/MMBtu	6.49E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Total VOC	5.5	lb/MMscf burned		AP-42, Sections 1.4 (U.S. EPA 2002)
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Acetaldehyde	0.0089	lb/MMscf burned	1.6127E-01	Air Resources Board. California Environmental Protection Agency. http://www.arb.ca.gov/app/emsinv/catef_form.html
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Benzene	0.0021	lb/MMscf burned	3.8182E-02	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Dichlorobenzene	1.2000E-03	lb/MMscf burned	2.1818E-02	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	7,12-Dimethylbenz(a)anthracene*	1.6000E-05	lb/MMscf burned	2.9091E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Formaldehyde	0.0750	lb/MMscf burned	1.3636E+00	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Hexane	1.8000E+00	lb/MMscf burned	3.2727E+01	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	2-Methylnaphthalene	2.4000E-05	lb/MMscf burned	4.3636E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	3-Methylchloranthrene*	1.8000E-06	lb/MMscf burned	3.2727E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Naphthalene	6.1000E-04	lb/MMscf burned	1.1091E-02	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Toluene	3.4000E-03	lb/MMscf burned	6.1818E-02	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Total PM	1.9	lb/MMscf burned		AP-42, Sections 1.4 (U.S. EPA 2002)
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Acenaphthene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Acenaphthylene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10-natural gas	Natural Gas	Anthracene*	2.4000E-06	lb/MMscf burned	1.2632E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Benz(a)anthracene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Benzo(a)pyrene*	1.2000E-06	lb/MMscf burned	6.3158E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Benzo(b)fluoranthene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Benzo(g,h,i)perylene*	1.2000E-06	lb/MMscf burned	6.3158E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Benzo(k)fluoranthene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Chrysene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Dibenzo(a,h)anthracene*	1.2000E-06	lb/MMscf burned	6.3158E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Fluoranthene	3.0000E-06	lb/MMscf burned	1.5789E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Fluorene	2.8000E-06	lb/MMscf burned	1.4737E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Indeno(1,2,3-cd)pyrene*	1.8000E-06	lb/MMscf burned	9.4737E-05	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Phenanathrene	1.7000E-05	lb/MMscf burned	8.9474E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion
Boiler-Max MMBTU/hr<10- natural gas	Natural Gas	Pyrene	5.0000E-06	lb/MMscf burned	2.6316E-04	AP-42, Sections 1.4 (U.S. EPA 2002) Natural Gas Combustion

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Natural Gas Engines 2 cycle rich	Natural Gas	VOC	5.152709841	lb/MMscf		AP-42, Section 5.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Acetaldehyde	2.79E-03	lb/MMscf	5.41E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Acrolein	2.63E-03	lb/MMscf	5.10E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Benzene	1.58E-03	lb/MMscf	3.07E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	1,3-Butadiene	6.63E-04	lb/MMBtu	1.29E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Carbon Tetrachloride*	1.77E-05	lb/MMBtu	3.44E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Chlorobenzene*	1.29E-05	lb/MMBtu	2.50E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Chloroform*	1.37E-05	lb/MMBtu	2.66E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Dichlorobenzene	1.20E-03	lb/MMscf	2.33E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	1,3-Dichloropropene*	1.27E-05	lb/MMBtu	2.46E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	7,12-Dimethylbenz(a)anthracene*	1.60E-05	lb/MMscf	3.11E-04	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Ethylbenzene*	2.48E-05	lb/MMscf	4.81E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Ethylene Dibromide*	2.13E-05	lb/MMscf	4.13E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Formaldehyde	2.05E-02	lb/MMscf	3.98E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Hexane	1.80E+00	lb/MMscf	3.49E+01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Methanol	3.06E-03	lb/MMscf	5.94E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Methylene Chloride	4.12E-05	lb/MMscf	8.00E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	2-Methylnaphthalene	2.40E-05	lb/MMscf	4.66E-04	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	3-Methylchloranthrene*	1.80E-06	lb/MMscf	3.49E-05	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Naphthalene*	9.71E-05	lb/MMBtu	1.88E-03	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Propylene	0.016842105	lb/MMBtu	3.27E-01	Air Resources Board. California Environmental Protection Agency. http://www.arb.ca.gov/app/emsinv/catef_form.html
Natural Gas Engines 2 cycle rich	Natural Gas	Styrene*	1.19E-05	lb/MMBtu	2.31E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	1,1,2,2-Tetrachloroethane	2.53E-05	lb/MMBtu	4.91E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Toluene	5.58E-04	lb/MMBtu	1.08E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	1,1,2-Trichloroethane*	1.53E-05	lb/MMBtu	2.97E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Vinyl Chloride*	7.18E-06	lb/MMBtu	1.39E-04	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Xylenes (isomers and mixture)	1.95E-04	lb/MMBtu	3.78E-03	AP-42, Section 3.2 (U.S. EPA 2002)

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Natural Gas Engines 2 cycle rich	Natural Gas	o-Xylenes			0.01	EPA Speciate 4.2 Database
Natural Gas Engines 2 cycle rich	Natural Gas	m-Xylenes			0.01	EPA Speciate 4.2 Database
Natural Gas Engines 2 cycle rich	Natural Gas	PM	3.84E-02	lb/MMscf		AP-42, Section 5.2 (U.S. EPA 2002)
Natural Gas Engines 2 cycle rich	Natural Gas	Acenaphthene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Acenaphthylene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Anthracene*	2.40E-06	lb/MMscf	6.25E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Benz(a)anthracene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Benzo(a)pyrene*	1.20E-06	lb/MMscf	3.13E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Benzo(b)fluoranthene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Benzo(g,h,i)perylene*	1.20E-06	lb/MMscf	3.13E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Benzo(k)fluoranthene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Chrysene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Dibenzo(a,h)anthracene*	1.20E-06	lb/MMscf	3.13E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Fluoranthene	3.00E-06	lb/MMscf	7.81E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Fluorene	2.80E-06	lb/MMscf	7.29E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Indeno(1,2,3-cd_pyrene*	1.80E-06	lb/MMscf	4.69E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Phenanathrene	1.75E-05	lb/MMscf	4.56E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 2 cycle rich	Natural Gas	Pyrene	5.00E-06	lb/MMscf	1.30E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Natural Gas Engine 4 cycle lean	Natural Gas	VOC	0.12	lb/MMBtu		AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Acetaldehyde	8.36E-03	lb/MMBtu	6.97E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Acrolein	5.14E-03	lb/MMBtu	4.28E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Benzene	4.40E-04	lb/MMBtu	3.67E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Biphenyl	2.12E-04	lb/MMBtu	1.77E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	1,3-Butadiene	2.67E-04	lb/MMBtu	2.23E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Carbon Tetrachloride*	3.67E-05	lb/MMBtu	3.06E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Chlorobenzene*	3.04E-05	lb/MMBtu	2.53E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Chloroform*	2.85E-05	lb/MMBtu	2.38E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Dichlorobenzene	1.20E-03	lb/MMBtu	1.00E+00	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	1,3-Dichloropropene*	2.64E-05	lb/MMBtu	2.20E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	7,12-Dimethylbenz(a)anthracene*	1.60E-05	lb/MMBtu	1.33E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Ethylbenzene	3.97E-05	lb/MMBtu	3.31E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Ethylene Dibromide*	4.43E-05	lb/MMBtu	3.69E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Formaldehyde	5.28E-02	lb/MMBtu	4.40E+01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Methanol	2.50E-03	lb/MMBtu	2.08E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	2-Methylnaphthalene	3.32E-05	lb/MMBtu	2.77E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	3-Methylchloranthrene*	1.80E-06	lb/MMBtu	1.50E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Methylene Chloride	2.00E-05	lb/MMBtu	1.67E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	n-Hexane	1.11E-03	lb/MMBtu	9.25E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Naphthalene	7.44E-05	lb/MMBtu	6.20E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Phenol	2.40E-05	lb/MMBtu	2.00E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Propylene	0.012673684	lb/MMBtu	1.06E+01	Air Resources Board. California Environmental Protection Agency. http://www.arb.ca.gov/app/emsinv/catef_form.html
Natural Gas Engine 4 cycle lean	Natural Gas	Styrene*	2.36E-05	lb/MMBtu	1.97E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Tetrachloroethane	2.48E-06	lb/MMBtu	2.07E-03	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	1,1,2,2-Tetrachloroethane*	4.00E-05	lb/MMBtu	3.33E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Toluene	4.08E-04	lb/MMBtu	3.40E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	1,1,2-Trichloroethane*	3.18E-05	lb/MMBtu	2.65E-02	AP-42, Section 3.2 (U.S. EPA 2002)

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Natural Gas Engine 4 cycle lean	Natural Gas	2,2,4-Trimethylpentane	2.50E-04	lb/MMBtu	2.08E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Vinyl Chloride	1.49E-05	lb/MMBtu	1.24E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Xylene	1.84E-04	lb/MMBtu	1.53E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	o-Xylenes			0.01	EPA Speciate 4.2 Database
Natural Gas Engine 4 cycle lean	Natural Gas	m,p-Xylenes			0.01	EPA Speciate 4.2 Database
Natural Gas Engine 4 cycle lean	Natural Gas	PM	7.71E-04	lb/MMBtu		AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Acenaphthene	1.25E-06	lb/MMBtu	1.62E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Acenaphthylene	5.53E-06	lb/MMBtu	7.17E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Anthracene*	2.40E-06	lb/MMBtu	3.11E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Benz(a)anthracene*	1.80E-06	lb/MMBtu	2.33E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Benzo(b)fluoranthene	1.66E-07	lb/MMBtu	2.15E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Benzo(e)pyrene	4.15E-07	lb/MMBtu	5.38E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Benzo(g,h,i)perylene	4.14E-07	lb/MMBtu	5.37E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Benzo(k)fluoranthene*	1.80E-06	lb/MMBtu	2.33E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Chrysene	6.93E-07	lb/MMBtu	8.99E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Dibenzo(a,h)anthracene*	1.20E-06	lb/MMBtu	1.56E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Fluoranthene	1.11E-06	lb/MMBtu	1.44E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Fluorene	5.67E-06	lb/MMBtu	7.35E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Indeno(1,2,3-cd)pyrene*	1.80E-06	lb/MMBtu	2.33E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engine 4 cycle lean	Natural Gas	Phenanthrene	1.04E-05	lb/MMBtu	1.35E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engine 4 cycle lean	Natural Gas	Pyrene	1.36E-06	lb/MMBtu	1.76E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	VOC	0.03	lb/MMBtu		
Natural Gas Engines 4 cycle rich	Natural Gas	Acetaldehyde	2.79E-03	lb/MMBtu	9.30E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Acrolein	2.63E-03	lb/MMBtu	8.77E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Benzene	1.58E-03	lb/MMBtu	5.27E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	1,3-Butadiene	6.63E-04	lb/MMBtu	2.21E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Carbon Tetrachloride*	1.77E-05	lb/MMBtu	5.90E-02	AP-42, Section 3.2 (U.S. EPA 2002)

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Natural Gas Engines 4 cycle rich	Natural Gas	Chlorobenzene*	1.29E-05	lb/MMBtu	4.30E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Chloroform*	1.37E-05	lb/MMBtu	4.57E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	1,3-Dichloropropene*	1.27E-05	lb/MMBtu	4.23E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	7,12-Dimethylbenz(a)anthracene*	1.60E-05	lb/MMBtu	5.33E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Ethylbenzene*	2.48E-05	lb/MMBtu	8.27E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Ethylene Dibromide*	2.13E-05	lb/MMBtu	7.10E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Formaldehyde	2.05E-02	lb/MMBtu	6.83E+01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Methylene Chloride	4.12E-05	lb/MMBtu	1.37E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	2-Methylnaphthalene	2.40E-05	lb/MMBtu	8.00E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	3-Methylchloranthrene*	1.80E-06	lb/MMBtu	6.00E-03	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Naphthalene*	9.71E-05	lb/MMBtu	3.24E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Styrene*	1.19E-05	lb/MMBtu	3.97E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	1,1,2,2-Tetrachloroethane	2.53E-05	lb/MMBtu	8.43E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Toluene	5.58E-04	lb/MMBtu	1.86E+00	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	1,1,2-Trichloroethane*	1.53E-05	lb/MMBtu	5.10E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Vinyl Chloride*	7.18E-06	lb/MMBtu	2.39E-02	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	Xylenes (isomers and mixture)	1.95E-04	lb/MMBtu	6.50E-01	AP-42, Section 3.2 (U.S. EPA 2002)
Natural Gas Engines 4 cycle rich	Natural Gas	o-Xylenes			0.01	EPA Speciate 4.2 Database
Natural Gas Engines 4 cycle rich	Natural Gas	m-Xylenes			0.01	EPA Speciate 4.2 Database
Natural Gas Engines 4 cycle rich	Natural Gas	PM	9.50E-03	lb/MMBtu		
Natural Gas Engines 4 cycle rich	Natural Gas	Acenaphthene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Acenaphthylene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Anthracene*	2.40E-06	lb/MMBtu	2.53E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Benz(a)anthracene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Benzo(a)pyrene*	1.20E-06	lb/MMBtu	1.26E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion

Appendix C. HAP Factors (Cont.)

Source Category	Fuel Type	Pollutant	Emission Factors	Emission Factor Unit	% HAP	Emission Factor Source
Natural Gas Engines 4 cycle rich	Natural Gas	Benzo(b)fluoranthene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Benzo(g,h,i)perylene*	1.20E-06	lb/MMBtu	1.26E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Benzo(k)fluoranthene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Chrysene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Dibenzo(a,h)anthracene*	1.20E-06	lb/MMBtu	1.26E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Fluoranthene	3.00E-06	lb/MMBtu	3.16E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Fluorene	2.80E-06	lb/MMBtu	2.95E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Indeno(1,2,3-cd_pyrene*	1.80E-06	lb/MMBtu	1.89E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Phenanathrene	1.75E-05	lb/MMBtu	1.84E-01	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion
Natural Gas Engines 4 cycle rich	Natural Gas	Pyrene	5.00E-06	lb/MMBtu	5.26E-02	AP-42, Section 3.2 (U.S. EPA 2002) Natural Gas Combustion

Appendix D – Compressor Engine Workbook

Appendix E – Texas Oil and Gas Emissions Inventory

Appendix F – Formatted TexAer Files

www.erg.com

Specified Oil & Gas Well Activities Emissions Inventory Update

FINAL REPORT

Prepared for:

Texas Commission on Environmental Quality

Air Quality Division

Prepared by:

Eastern Research Group, Inc.

August 1, 2014

ERG N0. 0292.03.026.001

Specified Oil & Gas Well Activities Emissions Inventory Update

FINAL REPORT

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List of Acronyms

Acronym	Definition
AACOG	Alamo Area Council of Governments
AP-42	U.S. EPA's Compilation of Air Pollutant Emission Factors
API	American Petroleum Institute
bbl	Barrel
BPA	Beaumont-Port Arthur
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
CenSARA	Central States Air Resource Agencies
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
ERG	Eastern Research Group, Inc.
ENVIRON	Environ International Corporation
HGB	Houston-Galveston-Brazoria
lbs	Pounds
MMscf	Million standard cubic feet
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
PM_{10}	Particulate Matter less than10 microns in aerodynamic diameter
PTE	Potential to Emit
ppm	Parts per million
psig	Pounds per square inch gauge
RRC	Railroad Commission of Texas
scf	Standard cubic feet
SO_2	Sulfur Dioxide
TCEQ	Texas Commission on Environmental Quality
TCAT	Texas Center for Applied Technology
TERP	Texas Emissions Reduction Plan
tpy	Tons per year
VOC	Volatile Organic Compound
UBD	Under-balanced drilling
URS	URS Corporation

Executive Summary

Eastern Research Group, Inc. (ERG) is currently under contract with the Texas Commission on Environmental Quality (TCEQ) under Work Order No. 582-11-99776-FY14-26 to provide nonpoint area source oil and gas emissions inventory estimates for mud degassing activities and hydraulic pump engines used at well drilling sites in Texas. ERG also determined the effects of the provisions of the recently revised New Source Performance Standards (NSPS) Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution) on the 2013 emissions inventory estimates. This report describes ERG's findings relative to survey efforts undertaken to collect information on mud degassing activities and the use of hydraulic pump engines in the eight oil and gas basins found in Texas, an analysis of available mud degassing and hydraulic pump engine emission factor data, and an examination of the effects on emissions from the equipment located at upstream oil and gas sources as the requirements of Subpart OOOO are implemented.

Drilling mud is a blend of water, oil, or synthetic fluids, special clays, and other additives. Mud is used during drilling to cool and lubricate the drill bit, remove cuttings to the surface, and control pressure in the wellbore. As drilling proceeds through gas-bearing formations, gas becomes entrained in the drilling mud. After the mud comes to the surface, the entrained gas is released, resulting in volatile organic compound (VOC) and methane emissions.

Hydraulic pump engines are used during well completions to inject mixtures of water, proppants, and other additives at high pressure into petroleum-bearing rock formations to create fissures in the rock. The resulting fissures increase the conductivity of the source rock, increasing the flow rate of petroleum liquids and gas to the wellbore. This technique improves hydrocarbon recovery rates in petroleum-bearing formations that would otherwise be unproductive. The engines are typically diesel-fired engines and are a source of nitrogen oxides (NO_x), carbon monoxide (CO), VOC, and particulate matter (PM) emissions. These emissions typically occur only once during the completion of a well, but are significant in magnitude.

NSPS Subpart OOOO requires operators of certain equipment at upstream oil and gas production sites to control emissions from that equipment beginning in October 2012. These requirements only apply to equipment newly constructed or modified after August 23, 2011. As new wells are completed each year to replace older, non-productive wells, the requirements of Subpart OOOO will apply to an increasing percentage of the wells in Texas over time. Total emissions from the classes of affected equipment will continue to decrease over time as more equipment becomes subject to Subpart OOOO control requirements.

ERG recommends that the TCEQ calculate emissions from mud degassing activities during well drilling using county-level well spud data and the emission factor data obtained under this study. ERG recommends that the TCEQ calculate emissions from hydraulic pump engines based on the county-level horizontal well completion data and the activity and emission factor data obtained under this study. ERG recommends that the TCEQ calculate emissions from Subpart OOOO affected facilities based on county-level data on the number of new well completions since October 2012, Subpart OOOO emission standards, and the emission factors developed in this and previous studies.

1. Introduction

Eastern Research Group, Inc. (ERG) is currently under contract with the Texas Commission on Environmental Quality (TCEQ) under Work Order No. 582-11-99776-FY14-26 to provide updates to TCEQ's nonpoint area source oil and gas emissions inventory estimates. Specifically under this effort, ERG evaluated activity and emissions data needed to characterize typical emissions from hydraulic pump engines and mud degassing equipment located at upstream oil and gas production sites in Texas. Information relative to this analysis was obtained through a survey of oil and gas producers operating in Texas, as well as a comprehensive literature review and interviews with industry experts familiar with the operating characteristics and any ongoing studies for these processes.

In addition, ERG evaluated the effects of the provisions of the recently revised New Source Performance Standards (NSPS) Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution) on the inventory estimates. The results of these analyses were then used to update TCEQ's nonpoint area source oil and gas emissions inventory calculator.

Purpose of This Study

The purpose of this study is to develop and refine the methodologies and characterization factors needed to generate emission estimates from hydraulic pump engines and mud degassing activities at oil and gas wells across Texas, as well as to evaluate and incorporate controls required under NSPS Subpart OOOO. This was accomplished by:

- Conducting a review of available literature;
- Conducting a phone and email survey of Texas oil and gas producers;
- Researching the availability of emission factors specific to hydraulic pump engines and mud degassing;
- Analyzing the requirements of NSPS Subpart OOOO; and
- Proposing control factors and revised operating/equipment parameters to reflect the requirements of the NSPS.

ERG first conducted a review of available literature, looking for data on emissions from mud degassing, hydraulic pump engines, and the impacts of NSPS Subpart OOOO, which affects new or modified sources as early as August 2011, dependent upon equipment type. Academic and technical literature on equipment characterization, emissions control techniques, and available state and federal environmental agency guidance on calculating emissions from these operations were examined. Additionally, ERG conducted a targeted phone survey of Texas oil and gas producers, requesting information on the use of hydraulic pump engines and mud degassing operations at their oil and gas wells. Several oil and gas producers were interviewed, to gather information on current practices and trends in the industry that are specific to Texas.

Using this information, ERG developed region-specific activity data and emission factors for use in updating the statewide oil and gas nonpoint area source emissions inventory for the source categories of interest.

2. Oil and Gas Producing Regions in Texas

There are several distinct oil- and gas-producing regions in Texas. These regions, also referred to as basins, reservoirs, source rock, or productive formations, are characterized by differences in petrogeology, age, depth below surface, type of petroleum hydrocarbon produced (liquids, gas, both), and many other characteristics that make them unique from one another. Even within a single region, there exists considerable heterogeneity. These differences are very important for evaluating the emissions that occur from production activities at wells in these basins. Drilling companies, fracturing companies, and production companies (operators) utilize practices that may be unique to each region, and emissions from their activities can vary accordingly. This study accounts for these differences, where they are known.

Figure 2-1 identifies eight oil and gas basins found in Texas. These basin boundaries are determined at the level of the county, and are based on geographical areas having similar petrogeology. By doing this, emissions from oil and gas production activities can be more accurately allocated to a county, based on county-level activity and production data, and emission factors determined at the basin-level. Note that the Eagle Ford Shale has historically been considered part of the Western Gulf Basin for inventory purposes, but due to the recent high level of activity in this area, it has been broken out as a separate region to more accurately characterize the unique types of processes and operations occurring to develop this play.

TCEQ's nonpoint area source air emissions inventory estimates for upstream oil and gas operations are based on county-level activity and equipment/emissions profiles. Activity data, such as oil and gas well counts and oil and gas production are as reported by the Railroad Commission of Texas (RRC)[1]. The equipment characterization and emissions data used in the inventory has been developed and refined over the last several years from a variety of studies, including TCEQ's "*Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions*" [2] and a 2012 study "*2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States*" conducted by the Central States Air Resources Agencies (CenSARA).[3]

1 2013 oil and gas activity data provided by the TCEQ, based on a January 2014 extract of information by the RRC and provided to the TCEQ in March 2014.

2 "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide missions", TCEQ, November 24, 2010.

3 "2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States", Environ International Corporation and Eastern Research Group, Inc. December 21, 2012.

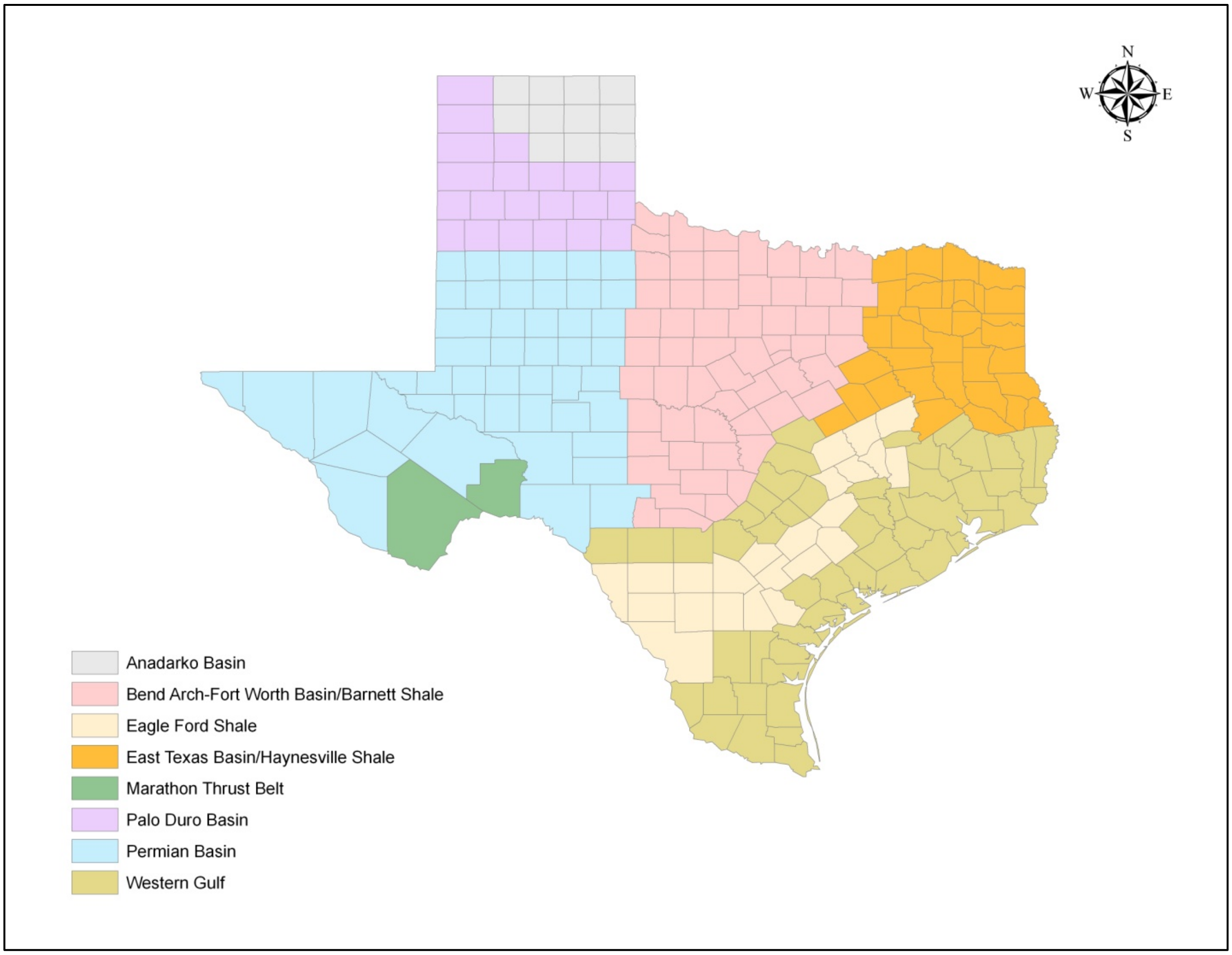

Figure 2-1. Oil and Gas Basins in Texas

This study sought to build upon these previous efforts to determine:

- Equipment characteristics and operational profiles of hydraulic pump engines used to stimulate wells in Texas;
- The appropriate emission factors to use for hydraulic pump engines used in Texas;
- The types of drilling mud used to drill oil and gas wells in Texas;
- The appropriate emissions profile data to use for mud degassing during oil and gas well drilling in Texas; and
- The implications of the recent revisions to the NSPS Subpart OOOO on the TCEQ nonpoint area source oil and gas emissions inventory.

3. Hydraulic Pump Engines

ERG investigated the use of hydraulic pump engines at drilling sites in Texas. The intent of this part of our study was to determine the frequency, quantity, location, and operating characteristics of these activities across the state, so that these emissions could be more accurately estimated in the TCEQ's nonpoint area source inventory. In arriving at the determinations presented in this report, ERG conducted a literature review, conducted a survey of oil and gas producers, gathered data on well completions from the RRC, reviewed data on engine emission factors, and interviewed industry representatives.

Hydraulic fracturing or stimulation involves the high pressure injection of a mixture of water, sand, proppants, and small amounts of chemicals and additives, to create fissures or fractures in rock formations. The fissures and fractures created during these operations stimulate an increase in the flow of natural gas and liquid hydrocarbons from the productive formation to the wellbore.[4] Hydraulic stimulation is used in petroleum-bearing formations that would normally be non-productive due to low porosity or permeability.[5] The intent is to increase the rate of recovery of petroleum liquids and gas from the reservoir surrounding the wellbore. Hydraulic stimulation is an expensive process, costing $135,000 or more per well[6], so operators use it when they judge that the increased productivity of the well will pay for the cost of this additional step.

3.1 Literature Review

ERG conducted a review of recent literature on well drilling techniques in general and hydraulic stimulation practices in particular, with the intent to gain a better understanding of the technique and the equipment required. ERG also reviewed literature on the petroleum geology in Texas, examining how well stimulation practices vary between the different oil and gas-producing formations in Texas. The following studies, articles, and web pages were found to be relevant.

3.1.1 Oil and Gas Emission Inventory, Eagle Ford Shale – Technical Report

The Alamo Area Council of Governments (AACOG), in cooperation with the TCEQ, published a study in April 2014, entitled "Oil and Gas Emission Inventory, Eagle Ford

4 Ginna Rodriguez and Chenchen Ouyang, "Air Emissions Characterization and Management For Natural Gas Hydraulic Fracturing Operations In the United States", Masters Thesis project, Univ. of Michigan, April 2013.

5 Porosity of a rock is a measure of the empty spaces) in a material, and is a fraction of the volume of void spaces divided by the total volume. Permeability is a measure of the ability of a material (such as rocks) to transmit fluids.

6 These are average cost figures for a USA well in 2011. Source: Michael Economides, "Hydraulic Fracturing: The State of the Art", Energy Tribune, August 26, 2011. Online: http://www.energytribune.com/8672/hydraulic-fracturing-the-state-of-the-art-2#sthash.rjPkQxRS.dpbs

Shale".[7] This study focused exclusively on the oil and gas operations in the Eagle Ford Shale formation in south Texas. The study examined the unique characteristics of the geology, hydrocarbon production, and production equipment used in the Eagle Ford Shale, and developed an air emissions inventory for oil and gas operations located in that region. The study gathered data on production, drill rig counts, well counts, well characteristics, and nonroad equipment from the RRC, companies that provide hydraulic pumping services,[8] TCEQ, oil and gas companies, and previous studies to compile a comprehensive view of the type and amount of equipment currently in use. The study then combined these activity data parameters with emissions factors from TCEQ's Drill Rigs Emission Inventory,[9] equipment manufacturers, the results of Texas Center for Applied Technology (TCAT) surveys,[10] and other sources, to develop an air emissions inventory. The study also examined development trends in the region, and, based on predicted production increases in the future, developed estimates of air emissions for 2015 and 2018 under three development scenarios.[11]

Of particular significance to this present study is the fact that the AACOG study estimated emissions from the use of hydraulic pump engines in the Eagle Ford Shale for the year 2012. The study examined data on hydraulic stimulation activity from studies done on other shale plays such as in Colorado,[12] the Marcellus Shale[13] in the northeast, the Barnett[14] and Haynesville[15] Shales in Texas, and from studies done by Ohio EPA and

---

[7] This study was finalized by the authors on November 30th, 2013 and accepted as final by TCEQ on April 4, 2014.

[8] Schlumberger, Baker-Hughes, and Halliburton are three of the largest companies providing hydraulic pumping services for the oil and gas production industry.

[9] Texas Commission on Environmental Quality, "Development of Texas Statewide Drilling Rigs Emission Inventories for the Years 1990, 1993, 1996, and 1999 through 2040", by Eastern Research Group, Inc., August 15, 2011. Online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821199776FY1105-20110815-ergi-drilling_rig_ei.pdf

[10] Texas Center for Applied Technology (TCAT), "Environmentally Friendly Drilling Systems Program Hydraulic Fracturing Phase Emissions Profile (Air Emissions Field Survey No. 1)", Nov. 2011.

[11] The study predicted air emissions under low, medium and high development scenarios. These development scenarios were based on estimates of ultimate recoverable reserves from the region, the number of drill rigs available, interviews with industry representatives about their plans for future development, production decline curves for wells in the region, and the prices for natural gas and petroleum liquids.

[12] Amnon Bar-Ilan, John Grant, Rajashi Parikh, Ralph Morris, ENVIRON International Corporation, "Oil and Gas Mobile Sources Pilot Study", July 2011. Online: http://www.wrapair2.org/documents/2011-07_P3%20Study%20Report%20(Final%20July-2011).pdf

[13] All Consulting, "NY DEC SGEIS Information Requests". Prepared for Independent Oil & Gas Association, Project no.: 1284, Sept. 16, 2010. Online: http://catskillcitizens.org/learnmore/20100916IOGAResponsetoDECChesapeake_IOGAResponsetoDEC.pdf

[14] Al Armendariz, "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", Prepared for Environmental Defense Fund, Jan. 26, 2009. Online: http://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf

[15] John Grant, Lynsey Parker, Amnon Bar-Ilan, Sue Kemball-Cook, and Greg Yarwood, ENVIRON International Corporation, "Development of an Emission Inventory for Natural Gas Exploration and Production in the Haynesville Shale and Evaluation of Ozone Impacts", August 31, 2009. Online: http://www.netac.org/UserFiles/File/NETAC/9_29_09/Enclosure_2b.pdf

the U.S. Dept. of Interior.[16] The AACOG study's authors also interviewed industry representatives, gathering information on how hydraulic stimulation equipment and processes have changed over time. The interviewers gathered information on: engine horsepower, the average amount of time it took to fracture a well, the number of fracturing stages, load factor, and the amount of water used. Like this study, the previous studies cited in the AACOG report used engine count, engine horsepower, hours of operation, and load factor to determine the emissions from a typical hydraulic fracturing job. Unlike this present study, the AACOG report used aerial imagery as part of their basis for estimating the number of hydraulic pump engines used at sites in the Eagle Ford Shale. Although imagery from 14 sites indicated that an average of 13.9 engines were used, the study's authors choose to use 12 engines per site in their emissions calculations, based on data from other studies and information obtained from local fracturing companies. The AACOG study based their load factor (30%) on information collected from hydraulic pump operators in the Eagle Ford play. The factors used in the AACOG study for calculating engine emissions from hydraulic fracturing are shown in Table 3-1.

Table 3-1. Emission Factors Used for Calculating Engine Emissions

Factor Description	Factor and Units	Source:
Number of Engines	12 / job	TCAT Eagle Ford Survey, ERG's Fort Worth Natural Gas Study, Aerial Imagery, Local Sources
Engine Horsepower	2,250 hp	TCAT Eagle Ford Survey, ERG's Drill Rig Emission Inventory for TCEQ
Total Hours per Job	54 hrs / job	ENVIRON's Haynesville Shale Report
Load Factor	30%	Local Sources
Engine Emission Factors	4.56g NO_x/hp-hr 0.24g VOC/hp-hr 2.67g CO/hp-hr	TCEQ's TERP emission factors for Tier 2 Engines[17] TCEQ's TERP emission factors for Tier 2 Engines TexN Model[18]

Thus, the AACOG study concluded that the total power expended by hydraulic pump engines to stimulate a typical well in the Eagle Ford Shale is 437,400 hp-hr.

The study noted that hydraulic stimulation practices have changed in the last few years, and described some of those changes. As more wells are completed in the Eagle Ford play, operators gain a better understanding of what works best in the geologic conditions presented by the source rock in the Eagle Ford Shale. A careful comparison

16 U.S. Department of the Interior, Bureau of Land Management, "Tumbleweed II Exploratory Natural Gas Drilling Project", DOI-BLM-UTG010-2009-0090-EA, June 2010. Online: http://www.blm.gov/pgdata/etc/medialib/blm/ut/lands_and_minerals/oil_and_gas/november_2011.Par.24530.File.dat/

17 TCEQ, April 24, 2010. "Texas Emissions Reduction Plan (TERP): Emissions Reduction Incentive Grants Program Technical Supplement No. 2, Non-Road Equipment".

18 TCEQ, August 18, 2008, Texas NONROAD (TexN) Model Version 1.0, Online: ftp://amdaftp.tceq.texas.gov/pub/Nonroad_EI/TexN/TexN_Users_Guide.pdf

of the AACOG study data and that from studies of hydraulic completions in other shale plays revealed that the techniques in the Eagle Ford that produce the best results are qualitatively different than those practices that lead to good results in other plays. This will be examined further in the next study reviewed for this report.

3.1.2 Hydraulic Technology – Optimizing Completion Design for the Eagle Ford Shale

ERG reviewed two studies published in The American Oil and Gas Reporter that detailed new approaches to hydraulic fracturing in the Eagle Ford Shale.

A study entitled "Approach Optimizes Completion Design", published in the August 2011 edition of The American Oil and Gas Reporter[19] examined the effect of a reservoir-specific completion strategy that accounts for the site-specific characteristics of the reservoir rock. The source rock at a well in DeWitt County was studied prior to fracturing. Analysis revealed that the reservoir rock was a clay-rich limestone with low quartz content and a low Young's modulus,[20] compared to the rock in the Barnett Shale, which is a very brittle siltstone with a high Young's modulus. The study examined how the properties of the reservoir rock played a role in determining what fracturing procedures and materials would provide the best results in opening the reservoir rock to allow the maximum gas and liquids to flow to the wellbore. Whole core data from a vertical section and mud log data from the lateral section were examined for the rocks' petrophysical characteristics and used to develop a completion strategy for each stage of the completion. The fluid mix was designed to control clay swelling, decrease the viscosity of the fluid over time, and inject larger than normal sized proppants to account for the relative softness of the rock. The large proppants were chosen to prevent 100% embedment of the proppant in the fracture face, which would, in effect, seal up the fractures that the hydraulic pumps create during the process. Each stage of the lateral was completed differently to account for changes in the brittleness/ductility index of the rock. Production data from the well, compared to that from other wells, showed that the production on this hybrid completion was superior to that produced from similar wells completed in the Eagle Ford using slick-water fracs.[21] The study authors concluded that the higher conductivity achieved with the hybrid completion accounted for the higher production.

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[19] The American Oil and Gas Reporter, "Approach Optimizes Completion Design", R. Borstmayer, N. Sargent, A. Wagner, and J. Mullen, August 2011.

[20] Young's Modulus is a measure of the stiffness of an elastic isotropic material and is used to predict how much a material sample extends under tension or shortens under compression. It might also be considered a measure of the brittleness or ductility of the rock.

[21] Compared to production from the three slick-water fraced wells examined in the study, production from the hybrid fraced well ranged from 750 – 2,250% higher, based on barrel oil equivalent production of gas and oil.

This 2011 study, published in a widely-available industry publication, showed that using a site-specific hybrid completion technique unique to the Eagle Ford Shale can increase well production by significant margins over using a completion technique typically used in other shale plays. ERG assumes that all other fracturing companies working in the Eagle Ford will quickly adopt these techniques. Although the study did state that the lateral length was 3,800 feet, it did not publish any information on the engine power or time spent to fracture each of the 11 stages. Therefore, total engine power requirements for this well could not be compared to the results from other studies conducted on other shale plays.

A study entitled “Pilot Wells Test Stimulation Approach”, published in the June 2011 edition of The American Oil and Gas Reporter[22] examined the effect of monitoring real-time microseismic activity in the reservoir rock during hydraulic fracturing for two wells. The study examined the effect of changing the hydraulic pumping schedule (pressure, time, proppants) using the microseismic monitoring, and found that “a stimulation technique that uses a shutdown during pumping to allow pressure relaxation, or equilibration, prior to reinitiating the fracturing process proved highly successful in increasing the estimated stimulated volume (ESV) in the reservoir rock.” The stimulation team changed their techniques for each stage of fracturing, varying the pressure and timing, based on the microseismic results from previous stages, with the intent to contain the fracturing within the target zone (which ranges from 100 to 300+ feet thick). The production logs from the wells showed positive correlation “between production contribution and the ESV derived from the analysis of microseismic monitoring done during hydraulic stimulation.” For the first well, pressure was slowly increased for each stage, containing the fracture in the target zone. For the second well, the stimulation team utilized significant variations in pumping pressure for five of the seventeen stages, to allow pressure relaxation for a period of 2 – 14 hours, prior to resuming pumping and finishing the fracture stage.

This article reported average lateral lengths were greater than 5,000 feet, and the number of stages at 10 -17 per lateral. The study did not publish any information on the engine power or time spent to hydraulically stimulate either of these wells. Therefore, total engine power requirements for these wells could not be compared to the results from other studies conducted on other shale plays.

[22] The American Oil and Gas Reporter, “Pilot Wells Test Stimulation Approach” A. Inamdar, T. Ogundare, D. Purcell, R. Malpani, K. Atwood, K. Brook, and A. Erwemi, June 2011.

3.1.3 Comparing Emissions from Hydraulic Operations Using Activity Data and Fuel Consumption

A Masters' Thesis project examined emissions from hydraulic stimulation operations in both the Eagle Ford Shale and the Marcellus Shale.[23] This study was unique in that the authors evaluated five air emissions models: three models were based on activity levels per source and two models were based on fuel consumption per source. The three models based on activity levels used data and methodology similar to that used in the AACOG study described above, the differences being in the use of load factors and emission factors. The general equation for these three activity-based models is:

Emissions = emission factor x horsepower x load factor x operating time.

The models based on fuel consumption differed in that one used total fuel consumption and AP-42 emission factors[24] while the second calculated emissions based on fuel consumption rate, hours of operation, and EPA Nonroad Tier 2 standards.[25] Both fuel consumption models used a constant for fuel density (7.11 lb/gal) and brake-specific fuel consumption for the equipment. The general equation for the two fuel usage models is:

Emissions = emission factor x brake-specific fuel consumption x fuel density x fuel consumption

The authors collected detailed engine activity and fuel usage data[26] from two well fracturing sites and applied it to the five models. The five models are described in Table 3-2.

Table 3-2. Emission Models Used for Estimating Emissions

Model	Source of Engine Emission Factors	Assumptions[27]
Activity Model 1	U.S.EPA – AP-42, Chapter 3.4	100% Load
Activity Model 2	U.S.EPA – AP-42, Chapter 3.4	Average Load, based on local data
Activity Model 3	U.S.EPA – Nonroad Tier 2 standards	Average Load, based on local data
Fuel Usage Model 1	U.S.EPA – AP-42, Chapter 3.4	100% Load
Fuel Usage Model 2	U.S.EPA – Nonroad Tier 2 standards	Average Load, based on local data

23 Ginna Rodriguez and Chenchen Ouyang, "Air Emissions Characterization and Management For Natural Gas Hydraulic Fracturing Operations in the United States", Masters Thesis project, Univ. of Michigan, April 2013.
24 Emission factors were from AP-42, Chapter 3.4, Large Stationary Diesel and All Stationary Dual-fuel Engines, October 1996.
25 All of the frac pump engines in the study were Tier 2 models.
26 The authors determined that the average fuel used for a fracturing job is 22,100 gallons for the Eagle Ford Shale and 20,800 gallons for the Marcellus Shale.
27 The average load factor is based on data collected onsite, and then weighting different loads during different portions of the job over the total time the frac pumps are used. For Fuel Usage Model 2, the fuel consumption rate is based on average load.

Total emissions were calculated from the engines used to power the hydraulic pumps, blender, frac control unit, hydration unit, sand king, and water transfer pump for each of the five models. By comparing results from the five models, the authors found that the magnitude of emissions is most sensitive to the emission factor and the load factor for the engines. The study found that emissions from the hydraulic pump engines account for 83-94% of all emissions from the engines used in hydraulic fracturing operations.

3.1.4 Hydraulic Stimulation in the Haynesville Shale

The Halliburton Company, a major provider of hydraulic pump services, produced a short brochure on the complex, heterogeneous conditions in the Haynesville Shale.[28] The brochure included the following information:

- The Haynesville Shale is approximately 10,500–13,500 ft deep, and its porosity is higher than other shales, indicating its ability to contain more gas;
- It has higher reservoir pressure than other North American unconventional shale plays;
- Average well vertical depths are 11,800 ft with bottomhole temperatures averaging 330°F, and wellhead treating pressures during stimulation commonly exceeding 10,000 psi. As a result, wells here *require almost twice the amount of hydraulic horsepower*[29] and more advanced fluid chemistry than other shale plays in the Southern U.S.; and
- In these deep wells, with fracture gradients of 1 psi/ft and low Young's modulus, there is also concern about the ability to sustain production with adequate fracture conductivity.

Based on the low Young's modulus, ERG would expect that the proppants used in the Haynesville Shale would be similar to that used in Eagle Ford Shale (e.g., larger in size), in order to maintain fracture conductivity to the wellbore after the fracture process is completed.

3.2 Hydraulic Pump Engine Survey and Findings

The hydraulic pump engines survey targeted oil and gas production companies and attempted to obtain information on the use of hydraulic pump engines during well completion activities at oil and gas wells. The companies targeted had significant recent activity in the six regions of interest for the survey.

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[28] Halliburton, Haynesville Shale, http://www.halliburton.com/en-US/ps/solutions/unconventional-resources/shale-gas-oil/shale-plays/haynesville-shale.page?node-id=hgjyd46z and http://www.halliburton.com/en-US/ps/solutions/unconventional-resources/shale-gas-oil/shale-plays/haynesville-shale.page?node-id=hgjyd46z

[29] While ERG's survey results for wells in the Haynesville Shale of East Texas appear to be at odds with this claim, the one company that submitted survey data gave us data for 7 vertical wells. The Halliburton Company is referencing the amount of hydraulic horsepower needed for stimulation of horizontal wells.

For the hydraulic pump engine survey, ERG attempted to contact persons at oil and gas production companies who were responsible for environmental and regulatory compliance. Letters were sent to a total of 93 contacts at 86 separate regional company offices located in Texas, Oklahoma, and surrounding states. The letters explained the survey, requested cooperation in gathering data, and included sample data collection forms. The survey letter requested data on the location, the type of well, the number of engines used, the horsepower of the engines, the percent full load for the engines, the number of fracturing stages, and the duration of each fracturing stage. The companies selected were identified from previous TCEQ surveys as companies which had provided data, and from the RRC database as operating companies that completed a significant[30] number of wells in the targeted basins during the year 2013. See Attachment A for the hydraulic pump engine letter and survey materials.

ERG followed up the letters with phone calls to each company contact until contact was made. In many cases, emails were sent to the company, either as a follow up to a telephone conversation, or in the event no telephone contact could be made. During phone calls, ERG requested participation and explained the survey to potential respondents.

ERG collected data on the use of hydraulic pump engines used during well completions for 79 wells from nine companies. The survey asked questions about:

- Location (County);
- Type of well (oil or gas well);
- Number of engines used;
- Horsepower of the engines;
- Percent full load for the engines;
- Number of fracturing stages; and
- Duration of each fracturing stage.

The data submitted for these 79 wells was compared with RRC data on the actual number of horizontal and vertical wells completed by each reporting company in 2013, by region and county, well type (oil or gas) and wellbore profile (horizontal, vertical, directional). The data was compiled into a spreadsheet, sorted by region, and calculations were performed to determine basin and state averages. This data is shown in Table 3-3:

[30] For purposes of this survey, a ‘significant’ number of wells completed by an operating company in 2013 ranged from 12 to over 100. Companies were found by querying the RRC database on the number of well completions, by district.

Table 3-3. Hydraulic Pump Engine Survey Data, by Region

Basin	Average Number of Engines	Average Horsepower	Average % Load	Average Number of Fracturing Stages	Average Duration of each Stage (hours)	Average Total Horsepower-hours Per Job
Anadarko Basin	15	2200	48%	10.4	1.58	254,563
Eagle Ford Shale	23	2290	76%	16.6	2.28	1,223,667
East Texas Basin/Haynesville Shale	8	1814	36%	2.1	1.04	11,271
Permian Basin	10	2313	36%	16.8	1.38	266,639
Statewide Average	14	2154	49%	11.5	1.57	439,035

Seven (7) additional companies responded to the survey with information to the effect that "Our company has not fractured any wells in those counties in 2013." ERG considered this to be useful information, as it provided information on those newly completed wells that were not hydraulically stimulated.

ERG obtained information on all 16 company's wells from the RRC database[31] for the basins of interest. This data included the region and county, well type (oil or gas) and wellbore profile (horizontal, vertical, directional). The number of wells represented by companies that responded but did not fracture any wells typically only represented a few wells. Many of these companies produced natural gas, and the market prices for natural gas for the past few years have not supported any new exploration. This data is shown in Table 3-4.

Table 3-4. Companies Responding to the Survey

Region	Companies Who Filled Out Survey Completely	Companies Reporting "No Wells Fractured"	Number of Wells Reported	Number of Wells Completed in 2013	Wells Completed in 2013 by Reporter	Reporter's 2013 Wells as % of Total
Anadarko Basin	1	0	8	847	111	13.1%
Eagle Ford Shale	5	0	48	3,182	654	20.6%
East Texas Basin/Haynesville Shale	1	0	7	678	7	1.03%
Fort Worth	0	1	-	-	-	-
Permian Basin	2	2	16	8,864	382	4.3%
Western Gulf	0	4	-	-	-	-

31 Data for well completions in 2013 was obtained using an operator-specific data query on the Railroad Commission website. Online: http://www.rrc.state.tx.us/about-us/resource-center/research/online-research-queries/

Attachment C contains the results of the hydraulic pump engine survey.

3.3 Recommendations for Using the Survey Findings

ERG recommends that the TCEQ use the findings in Table 3-3 above for estimating emissions from hydraulic pump engines. Where basin data was available, it has been used. For all other basins, the individual basin factors were averaged to determine a statewide value, which was then used in the other basins.

3.4 Hydraulic Pump Engine Emission Factors

For the 2011 base year TCEQ oil and gas nonpoint area source inventory, TCEQ used emission factors from the 2012 CenSARA study, which were derived using EPA's NONROAD2008 model. To update these factors for this study, average emission factors for 2013 and 2014 inventory years were developed. Using EPA's NONROAD2008 model, updated factors were developed based on the oil equipment source category bin (SCC 2270010010), and a diesel sulfur content of 15 ppm. Average emission factors were developed for engines between 1,000 and 3,000 horsepower, consistent with the engine sizes observed in the survey.

Table 3-5 below shows the emission factors for hydraulic pump engines for the 2011, 2013, and 2014 inventory years. As can be seen in the table, the emission factors have decreased over time as new engines replace older engines, resulting in a higher percentage of engines subject to the more stringent Tier 4 engine standards.

Table 3-5. Hydraulic Pump Engine Emission Factors

Pollutant	2011 (g/hp-hr)[a]	2013 (g/hp-hr)[b]	2014 (g/hp-hr)[b]
PM_{10}	0.227	0.184	0.172
NO_x	5.831	5.081	4.775
CO	1.318	1.076	1.021
VOC[c]	0.368	0.328	0.317
SO_2	0.010	0.0046	0.0045

[a] 2011 emission factors from CenSARA Inventory.
[b] 2013 and 2014 emission factors from EPA's NONROAD Model.
[c] VOC emission factor includes exhaust and crankcase emissions.

To account for this updated hydraulic pump engine information in the inventory, the Hydraulic Fracturing Pumps tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator was revised as follows:

- The PM_{10}, NO_x, CO, VOC, and SO_2 emission factors were updated to the 2013 values shown in Table 3-5;
- Table A was added to include the hydraulic pump engine operating characteristics for each basin from Table 3-3; and

- In the County-level emissions table: columns H through L were revised to lookup the appropriate operating factors from Table A.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for hydraulic pump engines using the updated operating characteristics and emission factor data in Tables 3-3 and 3-5.

4. Mud Degassing

Drilling mud is a mixture of special clays and additives with water, oil, or synthetic matter. Considerable heat and friction are generated by the drill bit as it removes rock at the bottom of the well. During drilling, the drilling mud is continuously pumped through the drill string and out through the drill bit. The circulating drilling fluid cools and lubricates the drill bit, and moves cuttings upwards through the wellbore toward the surface. Mud must have the capacity to suspend the fragments of solid material removed by the drill bit. If the mud does not circulate quickly enough, the drilled cuttings in the wellbore may accumulate and the drill string may get stuck.

To properly control the drilled materials and cutting suspension, the properties of drilling fluid are tested frequently at the rig site by a mud engineer using procedures specified in "Recommended Practice for Field Testing Water-Based Drilling Fluids", API Standard Method RP 13B-1. Measured properties include density and viscosity. Viscosity must be high enough that the drill cuttings will remain suspended, but low enough such that the pumps can overcome the friction and pump the mud up and out of the wellbore. Low-viscosity mud allows sand and cuttings to settle out, and gas to escape at the surface.[32] Mud density must be carefully controlled, and is gradually increased by the mud engineer through addition of special additives to the drill mud as the depth of the well increases. This is done to counteract formation pressure, which increases with depth.

As the drill bit approaches and penetrates oil and gas-bearing layers of rock (the producing formation or "play"), the mud engineer must be sure that the weight of the column of mud exceeds the pressure of fluids or gases in the productive formation. If not, and the subsurface pressure exceeds the downward pressure from the weight of the mud in the wellbore, a blowout may occur. Blowouts are both costly and dangerous, and drilling companies take extensive measures to prevent them. Still, the RRC records indicate that 24 blowouts occurred in Texas in 2013.[33]

In a broad sense, drilling mud can be classified as water-based, oil-based, synthetic, or an emulsion. The term "oil-based" is used for drilling mud prepared from petroleum distilled liquids, whereas the term "synthetic" is used for drilling mud prepared from non-aqueous liquids prepared from the reaction of organic building blocks, such as ethylene or methane.[34] Water-based muds may be fresh or saltwater based and typically include a type of clay that will stay suspended for a time after agitation has stopped. Oil-

[32] Lyons, William C. Working Guide to Drilling Equipment and Operations. Amsterdam: Gulf Pub./Elsevier, 2010. <http://public.eblib.com/EBLPublic/PublicView.do?ptiID=535200>.

[33] Railroad Commission of Texas, "Blowouts and Well Control Problems", Online: http://www.rrc.state.tx.us/oil-gas/compliance-enforcement/blowouts-and-well-control-problems/

[34] Growcock, Frederick B., and Arvind D. Patel. "The Revolution in Non-Aqueous Drilling Fluids (AADE-11-NTCE-33)." AADE National Technical Conference and Exhibition Held at the Hilton Houston North Hotel, Houston, Texas, April 12-14, 2011. (2011). <http://www.slb.com/resources/technical_papers/miswaco/AADE-11-NTCE-33.aspx>.

based and synthetic muds are generally expensive and hard to dispose of, but they are well suited for drilling the producing zones of deep, high temperature holes in which water-based muds solidify. [35]

Under-balanced drilling (UBD) describes a situation in which the hydrodynamic pressure of the drilling mud and circulating fluids in the well bore is less than the pressure of the well formation. This drilling technique can require surface equipment to separate drilling mud and hydrocarbons for recirculation, storage, flaring, and disposal.[36] UBD can cause a kick or a blowout to occur where there is an influx of reservoir fluid or gas into the wellbore. When properly managed, UBD allows for greater drilling velocity (aka rate of penetration). [37] When mud is over-balanced, it is forced into the surrounding rocks, and the solid particles form a filter or mud cake. This stabilizes the sides of the well and prevents subsurface fluids from flowing into the well. Over-balanced drilling is more typical.[38]

It is common to have a mud gas separator or degasser equipment located at the surface of the well to separate and safely remove large pockets of free gas from the drilling mud returned to the surface, but one is only used when drilling through the producing formation. It is necessary to remove the gas because it reduces the mud weight. Gas separators are effective on both water-based and oil-based muds. The vented gas may include toxic gases (such as hydrogen sulfide) from the drilling fluids processing system. One manufacturer of mud gas separators, GN Solids America, equips their separators with an electric ignition device to flare toxic gases.[39] Vacuum separators utilize negative pressure to withdraw entrained gases from the mud. In order for this to work, mud exiting the wellbore is pumped through a venturi choke. The pressure drops on the outlet side of the choke, enabling the entrained gases to expand and easily separate from the drilling mud. Atmospheric separators pump mud into a thin layer, relying on density differences between the gas and the mud to liberate gas. One separator design utilizes the thin layer approach inside a vacuum chamber to speed separation of gas from the drilling mud.

4.1 Available Mud Degassing Emission Factors

Limited information on the emissions from drilling mud is available, but there is a consensus opinion that a 1977 U.S. EPA publication "*Atmospheric Emissions from*

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[35] Lyons, William C. Working Guide to Drilling Equipment and Operations. Amsterdam: Gulf Pub./Elsevier, 2010. <http://public.eblib.com/EBLPublic/PublicView.do?ptiID=535200>.

[36] LeBlanc, Chris, Marco Amorim, and Roberto Piacentini. "Case Study: a High Throughput Mud-Gas Separator for Underbalanced Drilling." Offshore Technology Conference Held in Rio De Jeneiro, Brazil, 4-6 October 2011

[37] Personal communication with Bill Brannan of Nicklos Drilling Company. June 6, 2014

[38] Oil & Gas Production Protocol, published in February 2010 by The Climate Registry

[39] GN Solids America LLC. "Mud Gas Separator - GNZYQ Mud Gas Separator Features and Benefits." Web Accessed: 11 June 2014. <http://www.gnsolidsamerica.com/mud-gas-separator.html>.

Offshore Oil and Gas Development and Production" [40] is the best currently available estimate. The estimate presented in this study is based on engineering calculations of emissions from mud degassing at an offshore gas well using a water-based mud. The water-based emission rate represents gas liberated from rock drilled out of the wellbore, when drilling through a producing formation. The calculation assumes a penetration rate of 400 feet per day, 25% porosity, and reservoir pressure of 4,000 psig. The oil-based emission rate was calculated by assuming emissions from oil-based drilling mud were equivalent to emissions from diesel fuel stored in a fixed-roof storage tank with a turnover factor of 0.5.[41] The surface area of exposed mud is small. The gases separated from the mud in the mud separator are not counted. Although the mud turnover speeds vary over the course of the drilling event, this was not considered.

Four recent publications cite the 1977 EPA report as the original source for mud degassing factors:

- The American Petroleum Institute (API) publication "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry"[42] discusses mud degassing, and recommends that "site-specific methane concentration data should be used to estimate these emissions". The API document cites the mud degassing emission factors reported by US EPA in 1977.
- The Climate Registry's "Oil and Gas Production Protocol"[43] discusses emissions from mud degassing in the case of an underbalanced drilling operation, where the pressure in the wellbore is kept lower than the gas and fluid pressure in the formation being drilled. However, the discussion lacks a specific formula, and states that the volume of gas vented must be measured or estimated based on downhole pressure, wellbore diameter, and the duration of underbalanced drilling. Although other publications have mentioned that the drilling penetration rate is faster, and formation damage is lessened using underbalanced drilling, none suggests that underbalanced drilling is used when drilling producing shale formations, due to the risk of blowout. The Climate Registry document cites the mud degassing emission factors reported by US EPA in 1977.
- A report prepared by ENVIRON and ERG for the CenSARA States[44] cites the mud degassing emission factors reported by US EPA in 1977; and
- A report prepared by ERG for the TCEQ[45] cites the mud degassing emission factors reported by US EPA in 1977.

[40] "Atmospheric Emissions from Offshore Oil and Gas Development and Production". U.S. Environmental Protection Agency, EPA-450/3-77-026, June, 1977.

[41] Turnover factor is the ratio of throughput to tank capacity [See US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 7.1 Organic Liquid Storage Tanks. September 2006].

[42] American Petroleum Institute, "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry", August 2009

[43] Climate Registry, "Oil and Gas Production Protocol", Version 1.0, February 2010.

[44] ENVIRON, "2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States", prepared for the Central States Air Resources Agencies, December 21, 2012.

[45] Eastern Research Group, "Offshore Oil and Gas Platform Report - Final Report", August 16, 2010.

The most generally recognized mud degassing emissions factors are shown in Table 4-1, as presented in the API Compendium document.

Table 4-1. Mud Degassing Vented Emission Factors

Mud Type	Emission Factor (tonnes CH_4 / drilling day)[a]
Water-based	0.2605
Oil-based	0.0586
Synthetic	0.0586

[a] Note: 1 tonne = 1 metric ton = 2, 204.62262 pounds.

Additionally, the following studies were reviewed:

- In a recent study[46] published in the Proceedings of the National Academy of Sciences, the results of aerial sampling of methane in the air above wells being drilled in southwestern Pennsylvania (Marcellus Shale) was examined. The authors estimated that 34 grams methane per second was being released from wells in the drilling stage. Examination of the gas composition suggested that the methane plumes did not come from the shale rock, but arose from shallow coal pockets producing coal bed methane as the well was drilled through these formations. The methane was not directly attributed to drilling mud.
- A study sponsored by the Arkansas Department of Environment Quality entitled "Emissions Inventory & Ambient Air Monitoring of Natural Gas Production in the Fayetteville Shale Region"[47] examined air emissions from gas production activities in the Fayetteville Shale of Arkansas. Ambient monitoring was performed around the perimeter of six drilling sites, three hydraulic fracturing sites, four compressor stations, and a control site. The study found that concentrations of VOC at the sites other than drilling sites were at or below instrument detection limits, but that air samples around drilling sites had average VOC concentrations around 678 parts per billion.[48] The authors identified the likely source of VOC emissions as open tanks of oil-based drilling mud and cuttings.[49] The study did not identify the chemical composition of the VOC emissions, nor did it attempt to quantify emissions. The study noted that VOC emissions from gas production in the Fayetteville Shale were relatively low due to the low VOC content of the gas produced there (0.05% VOC), relative to the VOC content of gas produced in the Barnett Shale in Texas (8.2% VOC). Also, the Fayetteville Shale is a dry gas with little or no condensable hydrocarbons.

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46 Dana Caulton, et.al., "Toward A Better Understanding And Quantification Of Methane Emissions From Shale Gas Development", April 14, 2014. Online: http://www.pnas.org/content/early/2014/04/10/1316546111.abstract

47 David Lyon & Toby Chu, Arkansas Dept. of Environmental Quality, "Emissions Inventory & Ambient Air Monitoring of Natural Gas Production in the Fayetteville Shale Region", November 22, 2011.

48 Although there is no NAAQS standard for VOC, volatile hydrocarbons do contribute to ozone formation, and some of the VOCs produced during oil and gas exploration are also hazardous air pollutants. Without gas speciation data, the actual risk posed by these VOCs to the workers is unknown.

49 A company drilling in the Fayetteville Shale reported that an average well required 8.4 days to drill with an average lateral length of 4,985 feet, and that drilling normally utilizes oil-based drilling mud.

These two studies show that knowledge of site- or region-specific VOC content of gases is necessary for accurately estimating emissions from mud degassing.

In addition to the literature review, a number of individuals were contacted in an effort to determine if there were any current or recent emissions studies directly evaluating emissions from drilling mud:

- ERG contacted Dr. David Allen at The University of Texas at Austin. Dr. Allen is part of a group researching the climate impacts of natural gas.[50] The group's paper "Measurements of methane emissions at natural gas production sites in the United States," made no reference to mud degassing measurements.[51] Dr. Allen was not aware of any ongoing efforts to further characterize emissions from mud degassing.
- ERG contacted API and URS (their contractor and lead author of the compendium). Neither was aware of any more recent studies on mud degassing. Karin C. Ritter of API was not aware of any such studies either, but agreed to relay the TCEQ's interest in evaluating emissions from mud degassing to API members. [52]
- ERG also contacted David Lyon, the author of the Fayetteville Shale study mentioned above, who is currently with the Environmental Defense Fund (EDF). EDF is currently conducting a series of studies looking at emissions from upstream and midstream oil and gas exploration and production activities. Mr. Lyon was not aware of past or present research into mud degassing beyond the studies identified above.[53]

4.2 Mud Degassing Vendor Data

ERG identified five manufacturers of mud degassers and attempted to contact them to obtain information on mud degasser usage patterns across Texas. Unfortunately, these companies were unwilling to share customer details or mud degasser usage patterns.

ERG also reviewed available online literature from companies that manufacture mud degassing equipment:

- Derrick Equipment Company,[54] based in Houston, Texas, manufactures a mud degassing machine that utilizes thin film, high surface area, impact, turbulence, and vacuum technologies to quickly and efficiently remove entrained gases from water and oil-based drilling muds. Combined with other equipment in their line of products, the degasser processes used drill mud so that it can be quickly reused in the drilling operation.

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[50] Whittenberg, Lauren. "First Academic Study Released in EDF's Groundbreaking Methane Emissions Series." Environmental Defense Fund, 13 Sept. 2013. Accessed: 11 June 2014. <http://www.edf.org/media/first-academic-study-released-edf%E2%80%99s-groundbreaking-methane-emissions-series>.

[51] Personal communication with Dr. David Allen at The University of Texas at Austin. April 30, 2014.

[52] Personal communication with Karin C. Ritter of API and Terri Shires of URS Corporation. April 24, 2014 and April 29, 2014.

[53] Personal communication with David Lyon, May 5, 2014.

[54] Derrick Equipment Company, "Vacu-Flo Degasser", http://www.derrickequipment.com/home.aspx

- National Oilwell Varco,[55] based in Houston, Texas, manufactures a complete line of drilling fluid mixing, cleaning, cooling, pumping, and monitoring equipment. Their website indicates that “The mud (drilling fluid) system components condition the drilling fluid with the goal of lowering maintenance cost and decreasing the chance of equipment failure and hole and drilling problems.”

While this vendor information provided background knowledge about the process and equipment used in mud degassing, no emissions information was available from these sources.

4.3 Mud Degassing Survey Findings

The mud degassing survey targeted drilling companies and attempted to obtain information relating to mud degassing activities during drilling operations at oil and gas wells. The drilling companies provide rigs, equipment and crews to drill and service wells. The companies targeted had significant recent activity in the six regions of interest for the survey. These regions of interest are: Anadarko basin, Permian basin, Western Gulf basin, Bend Arch-Fort Worth basin/Barnett Shale, East Texas basin/Haynesville Shale, and the Eagle Ford Shale. As there is little gas or oil production in the Palo Duro and Marathon Thrust Belt basins, these areas were not targeted in this survey.

For the mud degassing survey, ERG attempted to contact persons responsible for drilling operations at the regional offices of their respective companies. Letters were sent to a total of 111 contacts at 64 separate regional company offices, representing 38 different drilling companies. The letters explained the survey, requested cooperation in gathering data, and included sample data collection forms. The survey letter requested data on the location, the type of well, the type of drilling mud used, the number of drilling days per well, and any control equipment used. See Attachment B for the mud degassing letter and survey materials. The companies selected were identified from the RigData database as companies that had drilled a significant number of wells[56] in the six regions of interest in the past three years.

ERG followed up the letters with phone calls to each company contact until contact was made. In many cases, emails were sent to the company, either as a follow up to a telephone conversation, or in the event no telephone contact could be made. During phone calls, ERG requested participation and explained the survey to potential respondents.

The mud degassing survey failed to produce any useful results or data. Most of the drilling companies contacted did not respond to repeated voice messages left for them. Of the three contacts that ERG spoke with, all indicated that they did not have the

[55] National Oilwell VARCO, http://www.nov.com/home.aspx?langtype=1033

[56] For purposes of this survey, a ‘significant’ number of wells drilled by a drilling company ranged from 7 to 1198, depending upon the basin, with the average being 138.

information we were seeking, or that it would be too difficult to obtain. One respondent indicated that mud formulation is the purview of the oil and gas companies, and not the drilling contractor and that they did not maintain records of mud usage or composition.[57]

The lack of response to the mud degassing survey by the drilling operations personnel may be due to several reasons:

- Some companies may feel this type of information is confidential in nature and wish to protect their operating practices;
- Drilling companies are not used to responding to air quality data collection surveys, and do not have the institutional capacity to respond;
- There was no real incentive for the drilling companies to participate, as drilling companies do not report emissions from their operations directly to TCEQ, and have no formal relationship with TCEQ as a regulated entity;
- The information requested was either not kept by the drilling companies, or was saved in different departments within a company, making it inconvenient to compile information on a particular well; and
- The operations people contacted were too busy managing drilling operations to respond.

One respondent indicated that they could not count on the roughnecks to provide the correct information on the type of mud used at every stage in the drilling process. Another indicated that the mud engineer for the operations company (the owner of the well) would be the person that would have the information, and requested that we contact them directly. This approach proved unsuccessful as well.

4.4 Mud Degassing Emission Factors

While no useful data was obtained as part of the survey, ERG was able to develop basin-specific mud degassing emission factors for Texas based upon the API emission factors originally derived from the 1977 EPA study. Using natural gas dehydrator data derived from a recent TCEQ study, [58] natural gas composition profiles for five oil and gas basins in Texas were calculated, along with a state averaged natural gas composition profile. This information is shown in Table 4-2 below.

Use of the wet stream data for estimating mud degassing emissions from gas wells is appropriate, and such data is readily available through dehydrator emissions inventory reports submitted to TCEQ. The wet stream, or "wet gas" composition data from the dehydrators is assumed to be representative of the composition of any gas released during mud degassing. This information was then used to develop updated mud degassing emission factors for mud degassing at gas wells based on the Texas-specific gas composition data. The resultant mud degassing composition data as used in the emissions calculation is shown in Table 4-3.

[57] Personal communication with Bill Brannan of Nicklos Drilling Company. June 6, 2014

[58] "Condensate Tank Oil and Gas Activities", Texas Commission on Environmental Quality, Air Quality Division, October 20, 2012.

Table 4-2. Basin-Level and State-Level Average Natural Gas Stream Composition Profiles

Composition in Weight %	Anadarko Basin		Bend Arch-Fort Worth Basin		East Texas Basin		Permian Basin		Western Gulf		State Average Profile	
	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream
Water	0.04	0.13	0.01	0.11	0.01	0.12	0.01	0.13	0.01	0.11	0.01	0.11
Carbon Dioxide	1.54	1.57	4.02	4.00	4.18	4.14	2.00	1.84	2.66	2.66	3.32	3.32
Hydrogen Sulfide	0.06	0.06	0.00	0.00	0.00	0.00	0.18	0.17	0.00	0.45	0.05	0.16
Nitrogen	2.07	2.06	2.56	2.53	1.36	1.34	2.87	2.83	0.76	0.73	1.78	1.75
Methane	79.66	79.70	73.99	73.34	81.31	80.70	61.68	58.39	77.15	76.53	75.13	74.31
Ethane	6.57	6.56	8.25	8.18	5.93	6.02	12.97	12.64	7.24	7.19	7.99	7.88
Propane	4.20	4.20	4.95	5.02	2.53	2.57	9.44	11.02	4.80	4.79	4.96	5.11
Isobutane	0.83	0.83	0.95	0.97	0.90	0.93	1.42	1.64	1.49	1.48	1.17	1.22
n-Butane	1.72	1.72	1.89	2.06	1.00	1.02	3.31	4.39	1.58	1.57	1.78	1.95
Isopentane	0.63	0.63	0.76	0.83	0.60	0.67	1.21	1.34	0.92	0.92	0.84	0.87
n-Pentane	0.67	0.67	1.02	1.09	0.44	0.48	1.10	1.47	0.66	0.65	0.76	0.83
Cyclopentane	0.04	0.04	0.11	0.15	0.16	0.15	0.03	0.07	0.11	0.07	0.07	0.11
n-Hexane	0.47	0.28	0.23	0.54	0.24	0.24	0.66	0.72	0.23	0.27	0.27	0.41
Cyclohexane	0.05	0.05	0.18	0.13	0.14	0.14	0.36	0.43	0.22	0.27	0.18	0.22
Other Hexanes	0.66	0.66	0.32	0.27	0.48	0.52	0.99	1.16	0.78	0.69	0.59	0.59
Heptanes	0.33	0.33	0.42	0.42	0.33	0.39	0.67	0.65	0.37	0.48	0.42	0.42
Methylcyclohexane	0.11	0.11	0.10	0.10	0.05	0.11	0.19	0.18	0.21	0.21	0.16	0.21
Benzene	0.04	0.04	0.04	0.04	0.09	0.13	0.26	0.29	0.04	0.08	0.08	0.08
Toluene	0.05	0.05	0.01	0.01	0.05	0.05	0.18	0.17	0.05	0.10	0.05	0.05
Ethylbenzene	0.01	0.01	0.00	0.01	0.01	0.01	0.05	0.05	0.01	0.01	0.01	0.01
Xylenes	0.02	0.06	0.01	0.02	0.01	0.03	0.05	0.05	0.02	0.06	0.02	0.03
C8+ Heavies	0.25	0.25	0.18	0.18	0.19	0.25	0.38	0.37	0.67	0.67	0.36	0.36
VOC[a]	10.06	9.93	11.17	11.84	7.20	7.68	20.30	24.00	12.17	12.32	11.72	12.46
Total Hydrocarbons[b]	96.29	96.19	93.41	93.36	94.44	94.40	94.95	95.03	96.57	96.04	94.84	94.65

[a] VOC includes Propane through C8+ Heavies

[b] Total Hydrocarbons includes VOC, Methane, and Ethane

Table 4-3. Mud Degassing Composition (Gas Wells)

Basin	CH_4 mol %	VOC MW	VOC mol %
Anadarko	90.68	55.91	3.24
Bend Arch-Fort Worth	87.59	55.48	4.09
East Texas	91.49	59.04	2.37
Marathon Thrust Belt[a]	88.36	56.35	4.22
Palo Duro[a]	88.36	56.35	4.22
Permian	78.53	54.72	9.46
Western Gulf	89.94	57.60	4.03

[a] The data for Marathon Thrust Belt and Palo Duro is the statewide average.

For oil wells, use of the same natural gas dehydrator data is not appropriate since casinghead gas (gas produced from oil wells) typically has less methane (and more VOC) than gas produced at gas wells. Additionally, as the gas from oil wells is not always collected, the gas analysis data used to estimate emissions from dehydration and needed to develop the profiles shown in Table 4-2 will not be available.

Therefore, to develop Texas-specific mud degassing information for oil wells, ERG utilized data from the 2012 CenSARA study. As part of that effort, oil well mud degassing composition information was obtained for the Anadarko and Permian basins (with data for the Permian basin used for the Marathon Thrust Belt basin, which includes two counties in southwest Texas adjacent to the Permian basin). ERG then used the data from the Anadarko and Permian basins to develop a statewide averaged profile, which was applied to the remaining basins. Table 4-4 presents the results of this analysis.

Table 4-4. Mud Degassing Composition (Oil Wells)

Basin	CH_4 mol %	VOC MW	VOC mol %
Anadarko	82.93	55.42	5.98
Bend Arch-Fort Worth[a]	81.78	54.32	6.52
East Texas[a]	81.78	54.32	6.52
Marathon Thrust Belt	80.62	53.22	7.06
Palo Duro[a]	81.78	54.32	6.52
Permian	80.62	53.22	7.06
Western Gulf[a]	81.78	54.32	6.52

[a] The data for Bend Arch-Fort Worth, East Texas, Palo Duro, and Western Gulf is the statewide average.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for drilling mud degassing using the updated composition data in Tables 4-3 and 4-4.

5. NSPS Subpart OOOO Inventory Evaluation

The intent of NSPS Subpart OOOO[59] is to reduce emissions of criteria pollutants at new, modified, or reconstructed affected facilities at oil and gas production, gathering, gas processing, and gas transmission/storage sites. NSPS Subpart OOOO does not regulate greenhouse gas emissions or hazardous air pollutants.

The facility types affected by Subpart OOOO include: natural gas wells that are hydraulically fractured, centrifugal compressors using wet seals, reciprocating compressors, continuous bleed natural-gas driven pneumatic controllers, storage vessels with a potential to emit (PTE) six tons per year (tpy) or more of VOC, piping component equipment (pump, pressure relief device, open-ended valve or line, valve, and flange or other connector in VOC or wet gas service) within a process unit located at onshore natural gas processing plants, and sweetening units located at onshore natural gas processing plants. NSPS Subpart OOOO applies to these facilities if they are newly constructed, modified, or reconstructed after August 23, 2011. Compliance dates vary by the facility type.

Table 5-1 shows the affected facilities, industry segment, compliance standard, and compliance dates for oil and gas units and processes regulated under Subpart OOOO. Table 5-1 also indicates if the affected facility is included in TCEQ's oil and gas nonpoint area source inventory.

Table 5-1. NSPS Subpart OOOO Summary

Affected Facility	Area Source?	Industry Segment or Location	Compliance Standard	Compliance Date
Natural gas wells hydraulically-fractured prior to 1/1/2015	Yes	Well sites (production)	Combust flowback emissions from completions	10/15/2012
Natural gas wells hydraulically-fractured on or after 1/1/2015	Yes	Well sites (production)	Recover and reuse/sell or combust flowback emissions from completions	01/01/2015
Centrifugal compressors using wet seals	No	Gathering and NG processing plants	95% reduction of VOC	10/15/2012
Reciprocating compressors	No	Gathering and NG processing plants	Change rod packing every three years	10/15/2012
Continuous bleed natural-gas driven pneumatic controllers	Yes	Production (well sites) and gathering	6 scfh bleed rate	10/15/2012
Continuous bleed natural-gas driven pneumatic controllers	No	NG processing plants	Zero bleed rate	10/15/2012

59 40 CFR 60, Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, http://www.ecfr.gov/cgi-bin/text-idx?SID=f701fdccf601c0b3200249b0ca81fbb6&node=40:7.0.1.1.1.103&rgn=div6#40:7.0.1.1.1.103.297.2

Table 5-1. NSPS Subpart OOOO Summary

Affected Facility	Area Source?	Industry Segment or Location	Compliance Standard	Compliance Date
Group I Storage Vessels (construction, modification or reconstruction commenced after 8/23/2011 and on or before 4/12/2013)	Yes	Production (well sites), gathering, NG processing, and NG transmission sites	Reduce VOC emissions by 95%, or maintain actual VOC emissions at less than 4 tpy without controls	04/15/2015, or within 60 days after startup
Group II Storage Vessels (construction, modification or reconstruction commenced after April 12, 2013)	Yes	Production (well sites), gathering, NG processing, and NG transmission sites	Reduce VOC emissions by 95%, or maintain actual VOC emissions at less than 4 tpy without controls	04/15/2014, or within 60 days after startup
Equipment Leaks (pump, pressure relief device, open-ended valve or line, valve, and flange or other connector in VOC or wet gas service)	No	Onshore NG processing plants	Implement a LDAR program. Leaks > 500 ppm must be repaired.	10/15/2012
Sweetening Units	No	Onshore NG processing plants	Reduce SO_2 as calculated	10/15/2012

5.1 Construction, Modification, Reconstruction, and Affected Facilities

NSPS Subpart OOOO requirements apply only to the types of facilities listed above that are newly constructed, modified, or reconstructed after August 23, 2011. "Construction" is defined as the fabrication, erection, or installation of a new affected "facility." Relocating an affected facility is not construction, modification, or reconstruction. "Modification" is defined as any physical or operational change to an existing facility which results in an increase in the hourly potential emission rate of any pollutant to which the NSPS standard applies.[60] Changes that do not constitute a modification include: increasing hours of operation, an increase in production rate without a capital expenditure, use of an alternative fuel or material if the source could utilize it prior, addition of an air pollution control device, change in ownership, and routine maintenance, repair, and replacement. "Reconstruction" is defined as replacing components at an existing facility, such that the capital cost of new components exceeds 50% of the capital cost of a comparable new facility, and it is technologically and economically feasible to meet applicable standards.

5.2 Effect of NSPS Subpart OOOO on the TCEQ Oil and Gas Nonpoint Area Source Oil and Gas Emissions Inventory

As shown above in Table 5-1, the following facilities/processes included in the TCEQ nonpoint area source inventory are affected by the rule:

[60] 40 CFR 60.14. An increase in emissions of a pollutant not regulated by the NSPS Subpart OOOO is not a modification.

- Natural gas wells hydraulically-fractured after 10/15/2012 and prior to 1/1/2015;
- Natural gas wells hydraulically-fractured on or after 1/1/2015;
- Continuous bleed natural-gas driven pneumatic controllers (at well sites);
- Group I Storage Vessels (at well sites); and
- Group II Storage Vessels (at well sites).

Since the NSPS regulations only affect facilities if they are newly constructed, modified, or reconstructed after August 23, 2011, an analysis was conducted to determine how to implement the required controls for each affected facility type in the inventory based on the requirements of the rule. Each of the affected source types is discussed in detail below, indicating how the affected percentage of the equipment population was determined, what the required controls are for each source type, and how these requirements were incorporated into the 2013 TCEQ oil and gas nonpoint area source emissions estimation calculator.

5.3 Natural Gas Well Completions

Under the requirements of NSPS Subpart OOOO, completions at natural gas wells that were hydraulically fractured after October 15, 2012 must be controlled with a flare. Completions at gas wells that are hydraulically fractured after January 1, 2015 must be controlled by capturing the gas for reuse or sale (reduced emissions completions) or flaring for exempted wells. There are currently no requirements in the rule to control emissions from oil well completions.

Information on the number of gas well completions that are hydraulically fractured is not readily available. However, information on the counts of vertical and horizontal gas wells spuds in 2013[61] is available. Therefore, ERG determined the percentage of gas well completions that were hydraulically fractured by assuming that the percentage of horizontal spuds in a county was equivalent to the percentage of horizontal completions, and that all horizontal well completions were hydraulically fractured. Using county-level data on the number of horizontal and vertical gas well spuds, the percent of all new gas wells that were horizontal, and therefore assumed to be hydraulically fractured, at the county level was determined. This data is included Table 5-2.

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
ANDERSON	0	0	0%
ANDREWS	1	0	0%
ANGELINA	0	2	100%
ARANSAS	2	0	0%
ARCHER	0	0	0%

[61] 2013 annual data was extracted January 2014 by the RRC and provided to TCEQ in March 2014.

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
ARMSTRONG	0	0	0%
ATASCOSA	0	0	0%
AUSTIN	0	1	100%
BAILEY	0	0	0%
BANDERA	0	0	0%
BASTROP	0	0	0%
BAYLOR	0	0	0%
BEE	25	5	17%
BELL	0	0	0%
BEXAR	0	0	0%
BLANCO	0	0	0%
BORDEN	0	0	0%
BOSQUE	0	0	0%
BOWIE	0	0	0%
BRAZORIA	4	8	67%
BRAZOS	0	0	0%
BREWSTER	0	0	0%
BRISCOE	0	0	0%
BROOKS	11	3	21%
BROWN	0	0	0%
BURLESON	0	0	0%
BURNET	0	0	0%
CALDWELL	0	0	0%
CALHOUN	1	0	0%
CALLAHAN	2	0	0%
CAMERON	0	0	0%
CAMP	0	0	0%
CARSON	0	0	0%
CASS	0	0	0%
CASTRO	0	0	0%
CHAMBERS	0	2	100%
CHEROKEE	4	1	20%
CHILDRESS	0	0	0%
CLAY	1	1	50%
COCHRAN	0	0	0%
COKE	0	0	0%
COLEMAN	1	0	0%
COLLIN	0	0	0%
COLLINGSWORTH	0	0	0%
COLORADO	0	2	100%
COMAL	0	0	0%
COMANCHE	1	0	0%
CONCHO	0	0	0%
COOKE	0	9	100%
CORYELL	0	0	0%
COTTLE	1	0	0%
CRANE	0	0	0%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
CROCKETT	2	0	0%
CROSBY	0	0	0%
CULBERSON	0	0	0%
DALLAM	0	0	0%
DALLAS	0	2	100%
DAWSON	0	0	0%
DE WITT	1	64	98%
DEAF SMITH	0	0	0%
DELTA	0	0	0%
DENTON	0	28	100%
DICKENS	0	0	0%
DIMMIT	1	192	99%
DONLEY	0	0	0%
DUVAL	8	0	0%
EASTLAND	0	0	0%
ECTOR	0	0	0%
EDWARDS	1	0	0%
EL PASO	0	0	0%
ELLIS	0	0	0%
ERATH	0	0	0%
FALLS	0	0	0%
FANNIN	0	0	0%
FAYETTE	0	0	0%
FISHER	0	0	0%
FLOYD	0	0	0%
FOARD	0	0	0%
FORT BEND	3	2	40%
FRANKLIN	0	0	0%
FREESTONE	20	5	20%
FRIO	0	4	100%
GAINES	0	0	0%
GALVESTON	0	2	100%
GARZA	0	0	0%
GILLESPIE	0	0	0%
GLASSCOCK	0	0	0%
GOLIAD	3	0	0%
GONZALES	0	0	0%
GRAY	0	0	0%
GRAYSON	0	1	100%
GREGG	4	3	43%
GRIMES	1	0	0%
GUADALUPE	0	0	0%
HALE	0	0	0%
HALL	0	0	0%
HAMILTON	0	0	0%
HANSFORD	0	0	0%
HARDEMAN	0	0	0%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
HARDIN	0	1	100%
HARRIS	5	1	17%
HARRISON	28	15	35%
HARTLEY	0	0	0%
HASKELL	0	0	0%
HAYS	0	0	0%
HEMPHILL	36	45	56%
HENDERSON	2	0	0%
HIDALGO	30	12	29%
HILL	0	0	0%
HOCKLEY	0	0	0%
HOOD	0	21	100%
HOPKINS	0	0	0%
HOUSTON	3	0	0%
HOWARD	0	0	0%
HUDSPETH	0	0	0%
HUNT	0	0	0%
HUTCHINSON	0	0	0%
IRION	2	0	0%
JACK	5	0	0%
JACKSON	7	4	36%
JASPER	0	0	0%
JEFF DAVIS	0	0	0%
JEFFERSON	1	7	88%
JIM HOGG	2	2	50%
JIM WELLS	7	0	0%
JOHNSON	0	34	100%
JONES	0	0	0%
KARNES	0	96	100%
KAUFMAN	0	0	0%
KENDALL	0	0	0%
KENEDY	2	1	33%
KENT	0	0	0%
KERR	0	0	0%
KIMBLE	0	0	0%
KING	0	0	0%
KINNEY	0	0	0%
KLEBERG	15	3	17%
KNOX	0	0	0%
LA SALLE	1	81	99%
LAMAR	0	0	0%
LAMB	0	0	0%
LAMPASAS	0	0	0%
LAVACA	10	0	0%
LEE	1	0	0%
LEON	6	4	40%
LIBERTY	3	2	40%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
LIMESTONE	13	0	0%
LIPSCOMB	0	15	100%
LIVE OAK	7	53	88%
LLANO	0	0	0%
LOVING	0	4	100%
LUBBOCK	0	0	0%
LYNN	0	0	0%
MADISON	3	0	0%
MARION	0	1	100%
MARTIN	0	0	0%
MASON	0	0	0%
MATAGORDA	1	5	83%
MAVERICK	0	0	0%
MCCULLOCH	0	0	0%
MCLENNAN	0	0	0%
MCMULLEN	2	36	95%
MEDINA	0	0	0%
MENARD	0	0	0%
MIDLAND	0	0	0%
MILAM	0	0	0%
MILLS	0	0	0%
MITCHELL	0	0	0%
MONTAGUE	0	81	100%
MONTGOMERY	0	0	0%
MOORE	5	0	0%
MORRIS	0	0	0%
MOTLEY	0	0	0%
NACOGDOCHES	0	2	100%
NAVARRO	0	0	0%
NEWTON	1	2	67%
NOLAN	1	0	0%
NUECES	7	5	42%
OCHILTREE	1	5	83%
OLDHAM	0	0	0%
ORANGE	0	3	100%
PALO PINTO	7	1	13%
PANOLA	51	58	53%
PARKER	0	54	100%
PARMER	0	0	0%
PECOS	0	0	0%
POLK	1	0	0%
POTTER	0	0	0%
PRESIDIO	0	0	0%
RAINS	0	0	0%
RANDALL	0	0	0%
REAGAN	0	0	0%
REAL	0	0	0%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
RED RIVER	0	0	0%
REEVES	0	12	100%
REFUGIO	11	0	0%
ROBERTS	2	9	82%
ROBERTSON	16	2	11%
ROCKWALL	0	0	0%
RUNNELS	0	0	0%
RUSK	7	22	76%
SABINE	0	0	0%
SAN AUGUSTINE	0	13	100%
SAN JACINTO	2	1	33%
SAN PATRICIO	9	6	40%
SAN SABA	0	0	0%
SCHLEICHER	0	0	0%
SCURRY	0	0	0%
SHACKELFORD	2	0	0%
SHELBY	3	9	75%
SHERMAN	5	0	0%
SMITH	0	0	0%
SOMERVELL	0	0	0%
STARR	42	5	11%
STEPHENS	18	0	0%
STERLING	0	0	0%
STONEWALL	0	0	0%
SUTTON	0	0	0%
SWISHER	0	0	0%
TARRANT	0	218	100%
TAYLOR	0	0	0%
TERRELL	0	0	0%
TERRY	0	0	0%
THROCKMORTON	3	0	0%
TITUS	0	0	0%
TOM GREEN	0	0	0%
TRAVIS	0	0	0%
TRINITY	0	0	0%
TYLER	2	3	60%
UPSHUR	0	0	0%
UPTON	0	0	0%
UVALDE	0	0	0%
VAL VERDE	0	0	0%
VAN ZANDT	0	0	0%
VICTORIA	7	0	0%
WALKER	0	0	0%
WALLER	5	0	0%
WARD	0	0	0%
WASHINGTON	0	0	0%
WEBB	22	201	90%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
WHARTON	7	0	0%
WHEELER	30	85	74%
WICHITA	0	0	0%
WILBARGER	0	0	0%
WILLACY	4	0	0%
WILLIAMSON	0	0	0%
WILSON	0	0	0%
WINKLER	0	0	0%
WISE	2	119	98%
WOOD	0	1	100%
YOAKUM	0	0	0%
YOUNG	1	0	0%
ZAPATA	3	2	40%
ZAVALA	0	0	0%

To address the changes in the inventory as a result of the requirements of NSPS Subpart OOOO as described above, the following changes have been made to the "Gas Well Completions" tab of TCEQ's oil and gas nonpoint area source emissions estimation calculator:

- In the Basin-Level Data table: added column for flaring capture/control efficiency. Assumed a value of 95% for all basins;
- In the Basin-Level Data table: added cells for NO_x and CO flaring emission factors. The values are 0.068 and 0.37 lb/MMSCF, respectively, for all basins;
- In the County-level emissions table: added a column to show % of completions controlled (flared);
- In the County-level emissions table: modified the title in column I to read "Uncontrolled VOC Emissions (tons/event)";
- In the County-level emissions table: modified the formula in column J to reflect controls; and
- In the County-level emissions table: added columns K and L for NO_x and CO emissions.

These changes reflect the impact of the NSPS Subpart OOOO requirements on hydraulically-fractured gas well completions after October 15, 2012, which will affect the 2013 and 2014 emissions inventories as hydraulically-fractured gas wells completed after this date must be controlled with flaring. The additional calculations for NO_x and CO reflect the combustion emissions from the flare. Note that beginning January 1, 2015, hydraulically-fractured gas well completions must be conducted using reduced emissions completions or flaring. This requirement will need to be considered in future inventories.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for natural gas well completions as a result of the requirements of NSPS Subpart OOOO.

5.4 Pneumatic Controllers

Under the requirements of NSPS Subpart OOOO, pneumatic devices at oil and gas wells that were completed after October 15, 2012 must achieve a leak rate of six scf/hr or less. In the current inventory, the leak rate for pneumatic devices at oil wells is estimated to be less than six scf/hr for every basin. Therefore, the calculation for emissions from pneumatic devices at oil wells has not been revised.

To determine the effects on the 2013 emissions inventory of this requirement for gas wells, the percentage of affected gas wells was needed. This was determined by calculating the percent of total gas wells in production in 2013 that were completed after October 15, 2012. ERG used RRC county-level data on well counts and district level data on well completions to estimate the number of wells completed at the county level for the periods October 15, 2012 to December 31, 2012, and January 1, 2013 to December 31, 2013. ERG then calculated the percentage of new wells in each county using the county-level sum of new wells (since October 15, 2012) and the current county-level well count. This data is included in Table 5-3.

Table 5-3. New Gas Wells 10/15/12 – 12/31/13

Basin Name	2012 New Gas Wells (10/15/12 – 12/31/12)	2013 New Gas Wells	Total Gas Wells in 2013	New Wells (10/15/12 – 12/31/13) as Percent of Total
Anadarko Basin	69	526	12,036	4.9%
Bend Arch-Fort Worth Basin	275	1,425	22,388	7.6%
Eagle Ford Shale	86	1,220	11,156	11.7%
East Texas Basin/Haynesville Shale	113	340	19,931	2.3%
Palo Duro Basin	5	37	934	4.5%
Permian Basin	44	317	18,215	2.0%
Western Gulf	81	599	10,598	6.4%

Once the percentage of affected wells was known, an updated basin-weighted average bleed rate could be determined by assuming that all pneumatic devices at new wells would have a bleed rate of six scf/hr, while the bleed rates for pneumatic devices at existing wells (in existence prior to October 15, 2012) would not change. Table 5-4 presents the bleed rates for existing pneumatic devices, for new pneumatic devices (at gas wells brought into production after October 15, 2012), and the updated 2013 basin-weighted average bleed rate of all pneumatic devices within a basin.

Table 5-4. Updated Basin-Weighted Average Bleed Rate (Gas Wells)

Basin Name	Bleed Rate, Pre 10/15/2012 Devices (scf/hr/device)	Bleed Rate, Post 10/15/2012 Devices (scf/hr/device)	2013 Basin Weighted Average Bleed Rate (scf/hr/device)
Anadarko Basin	12.45	6	12.13
Bend Arch-Fort Worth Basin	6.2	6	6.18
Eagle Ford Shale	10.75	6	10.19
East Texas Basin/Haynesville Shale	17.59	6	17.33
Palo Duro Basin	8.58	6	8.46
Permian Basin	8.79	6	8.73
Western Gulf	7.78	6	7.67

As can be seen in the table, for the 2013 inventory, the average bleed rate of pneumatic devices at gas wells has slightly declined in each basin. Over time, as the percentage of wells subject to the six (scf/hr) bleed rate limitation increases, the average bleed rate of pneumatic devices will continue to decline.

In the Gas Well Pneumatic Devices tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator, the column titled "Basin Bleed Rate (scf/hr)" was revised to "Basin Weighted Average Bleed Rate (scf/hr/device)" to reflect the updated bleed rates shown in Table 5-4. These changes reflect the impact of the Subpart OOOO requirements on gas well pneumatic devices at wells completed after October 15, 2012 on the 2013 emissions inventory.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for pneumatic controllers as a result of the requirements of NSPS Subpart OOOO.

5.5 Oil and Condensate Storage Vessels

Storage vessels are defined as a single tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water. Fuel and chemical injection tanks, skid-mounted/mobile tanks, process vessels, and pressure vessels are excluded. Subpart OOOO applies to storage tanks installed, modified, or reconstructed after August 23, 2011, having a PTE of VOC greater than or equal to six tpy, and located in the: oil and natural gas production, oil and natural gas gathering, natural gas processing, or natural gas transmission and storage segments of the industry.

Under the requirements of the rule, storage vessels are separated into two groups based on date of construction/modification. Group I storage vessels are those vessels constructed, reconstructed, or modified after August 23, 2011, and on or before April 12, 2013. The PTE of Group I storage vessels must be estimated no later than October 15, 2013. Any Group I storage vessel determined to have a PTE greater than six tpy must be in compliance with the emission standards by April 15, 2015. Therefore, for purposes of revising the 2013 inventory, no control is assumed for Group I storage tanks as controls for these tanks are not required until 2015.

Group II storage vessels are those vessels constructed, reconstructed, or modified after April 12, 2013. The PTE of Group II storage vessels must be estimated no later than thirty days after startup. Any Group II storage vessel with PTE greater than six tpy must be in compliance with the emission standards by April 15, 2014 or within 60 days after startup. Pursuant to 40 CFR 60.5365, the PTE from storage vessels can be calculated via testing or by using a generally accepted model or calculation methodology, based on the maximum average daily throughput. Note that the current TCEQ area source emissions inventory accounts for a percentage reduction due to control devices installed on existing equipment at condensate tanks. [62]

A comparison of storage vessel PTE vs. throughput, using current TCEQ area source emissions inventory emission factors for oil storage tanks (1.60 lb VOC released per barrel of oil throughput) and condensate storage tanks (3.15 – 11.02 lb VOC per barrel of throughput), shows that an oil storage tank with throughput of less than 20 bbl per day has a PTE of less than six tpy of VOC, before the effect of any controls.[63] Since the TCEQ air emissions inventory emission factors for condensate storage tanks vary by region,[64] the throughput of condensate that results in a PTE of less than six tpy varies across Texas. For example, condensate production of 2.5 bbl/day in the Western Gulf basin results in PTE of less than six tpy VOC, while condensate production of 10 bbl/day in the Anadarko basin results in PTE of less than six tpy VOC, before the effect of any controls.

Vapors that are collected and re-routed to a process do not count towards PTE. A study conducted by ERG for TCEQ in 2012 on condensate tank emissions[65] showed that many operators were installing multi-stage depressurizing devices and condensers on their wells to capture and sell that portion of their petroleum production that might have previously been lost as emissions. As these devices increase production recovery efficiency, they are not controls, so PTE would be calculated after the effect of these devices.

For any storage tank with a PTE greater than six tpy, VOC emissions must be reduced by 95% (capture + control) using either a closed vent system and a control device or a floating roof. Control devices must undergo a performance test, except for: flares that

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[62] Control factors for VOC emissions from condensate storage tanks are as follows: Anadarko basin-17.1%, Bend Arch-Fort Worth-11.8%, East Texas-10.5%, Eagle Ford Shale-46.0%, Permian-19.5%, and Western Gulf-12.2%.

[63] Based on emissions of 1.6 lb VOC per bbl oil throughput: 1.6 lb/bbl x 365 days/yr x 1 ton/2,000 lb x 20 bbl/day = 5.84 tpy of VOC.

[64] VOC emissions per bbl of condensate throughput: Anadarko basin-3.15, Bend Arch-Fort Worth-9.76, East Texas-4.22, Eagle Ford Shale-10.46, Permian-7.07, and Western Gulf-11.03. Calculation methodology is identical to that for oil.

[65] "Condensate Tank Oil and Gas Activities", Texas Commission on Environmental Quality, Air Quality Division, October 20, 2012.

are designed and operated in accordance with §60.18(b), large boilers or process heaters (> 44 megawatts), hazardous waste incinerators, or a control device that meets the performance requirements of §60.5412(a). To account for declining production, the control device can be removed from controlled storage vessels whose actual uncontrolled emissions drop to less than four tpy for more than 12 months. Control devices must also meet continuous monitoring requirements.

Since Group I storage vessels have until April 15, 2015 to comply, the effect of Subpart OOOO on emissions from these wells has not been considered for the 2013 inventory. For Group II storage vessels, the set of storage vessels that will need to be considered are those storage vessels that commenced production from April 12, 2013 through December 31, 2013. To determine the number of wells and the liquids production of the storage vessels at oil and gas production sites that were required to control emissions beginning June 11, 2013 (60 days after a date of 1st production of April 12, 2013), ERG used RRC lease-level data on oil and condensate production and TCEQ's basin-specific VOC emission factors for oil and condensate storage tanks[66],[67] to estimate the number, percentage, and liquids production of oil and gas wells completed since August 23, 2011 whose storage vessels have a PTE of VOC greater than six tpy. Although the Subpart OOOO compliance dates are different for isolated new wells and new wells located on a pad with an existing well, in doing these calculations, ERG assumed that all new wells are isolated and that production from a single well goes into a single storage tank. To simplify the determination of when a well begins production, ERG assumed that production begins on the date of completion. To simplify the determination of when a storage tank began complying with Subpart OOOO requirements, ERG assumed that storage tanks were in compliance on the date of completion.

The RRC lease-level data indicate that 2,638 new oil wells and 766 new gas wells were completed after April 12, 2013, and before January 1, 2014. Emissions calculations based on liquids production information and basin-specific emission factors for those wells described above show that 1,557 new oil wells and 356 new gas wells producing liquids are subject to the Subpart OOOO control requirements for the year 2013. The 2013 production represented by these wells (83,932,001 bbl oil and 8,636,341 bbl condensate) was compared with the total production for all new wells completed after April 12, 2013 and before January 1, 2014 (86,451,460 bbl oil and 8,719,058 bbl condensate), indicate that 97.1% of all new oil production and 99.1% of all new condensate production are subject to Subpart OOOO requirements for storage vessels.

When the 2013 oil and condensate production represented by these subject wells is compared with RRC data for 2013 statewide oil and condensate production (687,486,763 bbl oil and 107,651,266 bbl condensate), the data show that 12.2% of total

[66] "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide missions", TCEQ, November 24, 2010

[67] "Condensate Tank Oil and Gas Activities", TCEQ, October 10, 2012

statewide 2013 oil production and 8.02% of total statewide 2013 condensate production is subject to Subpart OOOO storage vessel control requirements. The breakdown by basin is shown in Table 5-5.

To account for these controls in the inventory, the Oil Storage Tanks tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator was revised as follows:

- A new table was added with data showing the percentage of basin-level oil production that is subject to Subpart OOOO requirements for 2013;
- A new table was added showing the emission control requirements (95% control) for oil production that is subject to Subpart OOOO requirements;
- A column was added to the County-level emissions table to account for % of 2013 production controlled; and
- In the County-level emissions table, the calculations for VOC, Benzene, Toluene, Ethylbenzene, and Xylene were revised to reflect the changes in emissions due to the Subpart OOOO control requirements for emissions from storage vessels constructed after April 12, 2013.

In the Condensate Storage Tanks tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator, similar changes were made. The calculation for the control percentage for each basin is complicated by the fact that a survey[68] conducted in 2012 showed that a significant percentage of statewide condensate production was already controlled. For 2012, the control factor for storage tanks that already had recovery or control devices installed ranged from 11.8% for condensate-producing gas wells in the Bend Arch-Fort Worth Basin to 46% for gas wells in the Eagle Ford Shale. Since the wells constructed in 2013 that are subject to Subpart OOOO requirements are new wells with the requirement to control emissions from storage vessels, ERG made the simplifying assumption that the percent of regional condensate production represented by these new 2013 wells would be added to the control percentage of the production that was already controlled. As required by the rule, the control percentage applied to the new subject wells is 95%.

Therefore, the Condensate Storage Tank EFs tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator was revised as follows:

- The Control Factors in Table A and Table B were revised to increase the existing regional control factors by the percentages shown above (and reflecting the 95% control requirement for controlled production). These revised control factors are used in the emissions calculations in the Condensate Storage Tanks tab of the spreadsheet;
- Table C was added to show the % of total production within a basin that is subject to the NSPS control requirements; and
- A table was added to show the required NSPS control of 95%.

[68] "Condensate Tank Oil and Gas Activities", TCEQ, October 10, 2012

No revisions were needed to the Condensate Storage Tanks tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator as the control factors are pulled from the Condensate Storage Tank EFs tab and inherently incorporate the NSPS Subpart OOOO control requirements.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for storage vessels as a result of the requirements of NSPS Subpart OOOO.

Table 5-5. Percentage of 2013 Oil and Condensate Production Subject to Subpart OOOO Requirements

Basin	Oil			Condensate		
	Production Subject to Subpart OOOO (bbl)	Total Production (bbl)	% of Production Subject to Subpart OOOO	Production Subject to Subpart OOOO (bbl)	Total Production (bbl)	% of Production Subject to Subpart OOOO
Anadarko Basin	174,099	10,609,144	1.6%	1,066,246	14,038,374	7.60%
Bend Arch-Fort Worth Basin	787,645	20,391,120	3.9%	328,549	5,147,458	6.38%
Eagle Ford Shale	75,495,269	263,909,215	28.6%	6,493,095	68,335,461	9.50%
East Texas Basin	85,893	7,994,511	1.1%	13,158	624,895	2.11%
East Texas Basin/Haynesville Shale	76,800	6,087,890	1.3%	118,595	4,109,868	2.89%
Marathon Thrust Belt	0	5,668	0.0%	0	54,345	0.00%
Palo Duro Basin	558,642	4,124,773	13.5%	3,644	55,043	6.62%
Permian Basin	5,592,846	344,009,390	1.6%	964	2,472,622	0.04%
Western Gulf	789,990	16,494,090	4.8%	576,967	9,366,101	6.16%
Western Gulf/Beaumont-Port Arthur	13,247	2,512,043	0.5%	355	1,905,094	0.02%
Western Gulf/Houston-Galveston-Brazoria	369,936	11,348,919	3.3%	39,014	1,542,005	2.53%

6. Conclusions

ERG recommends that the TCEQ update the nonpoint area source oil and gas emissions inventory as described in this report for the following source types:

- Condensate storage tanks;
- Gas well completions;
- Gas well pneumatic devices;
- Hydraulic pump engines;
- Mud degassing (oil and gas wells); and
- Oil storage tanks.

Under the requirements of the recently revised NSPS Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution), certain new condensate storage tanks, gas well completions, gas well pneumatic devices, and oil storage tanks require emissions control or emissions reduction strategies. Based on the findings of this study, the rule revisions have had a particularly notable impact on emissions from oil and condensate tanks due to the increase in hydrocarbon liquids production in Texas over the last few years. As new liquids production is brought on-line, particularly in areas such as the Eagle Ford Shale, storage tank control requirements are triggered such that emissions on a per barrel basis are much lower than from older wells.

For mud degassing, limited data was available to improve the current emissions estimate. This source category is not regulated; is not covered under Subpart W of the Greenhouse Gas Reporting Rule; and has not typically been considered a large emitting source. However, Texas-specific gas composition data were used to refine the estimates for mud degassing to reflect basin-specific gas composition in Texas.

Finally, updates to the input variables used to estimate emissions from hydraulic pump engines have resulted in a large increase in emissions for this category. Previously, emissions were based on input variables developed under the CenSARA 2012 emissions inventory project which reflected an average of 3.5 engines rated at 1,258 hp operating for approximately 9 hours to complete well perforation and stimulation. As shown in Table 3 above, well stimulation operations in Texas require significantly more engines, at a higher hp, and increased operational time to complete the process.

Attachment D contains an updated version of TCEQ's oil and gas nonpoint area source emissions estimation tool reflecting the revisions described above.

Attachment A

Hydraulic Pump Survey Letter

EASTERN RESEARCH GROUP, INC.

Dear [Insert Operator_Contact_Name], [Insert Operator_Contact_Title]

[Insert Operator_Company_Name] [Date]

Eastern Research Group (ERG), an independent research organization, is conducting a study on emissions from pump engines used in hydraulic stimulation and perforation activities for the Texas Commission on Environmental Quality (TCEQ). The purpose of this study is to develop equipment inventories and usage data for estimating emissions from hydraulic pump engines for each of the oil and gas producing regions in Texas. The study results will assist the TCEQ in refining the Texas air emissions inventory.

Hydraulic pump engine emissions are currently estimated by TCEQ using activity data from a 2012 Central States Air Resources Agencies (CenSARA) study. The purpose of this survey is to gather Texas-specific data on hydraulic pump engine activities so that TCEQ can refine its emissions estimates. To support this effort, the TCEQ is seeking information from Texas oil and gas drilling/hydraulic stimulation companies to assist in development of refined, county-specific equipment and usage data.

We are asking for your participation in this voluntary survey that will involve sharing information regarding the number and horsepower of engines used, and the amount of time they are used. ***Individual wells and rigs do not need to be identified.*** The information your company provides will be used for statistical purposes only in order to develop county-level and basin-level estimates and will not be republished or disseminated for other purposes. **The information you provide will be held confidential.**

ERG will contact your company via phone to discuss this effort and collect any information you are willing to share. We are seeking basin-specific hydraulic pump engine usage information for oil and gas well sites hydraulically stimulated in the [Insert Basin_name] [Insert counties_text] The specific information we are requesting for each well hydraulically stimulated in 2013:

- County
- Well type (oil or gas)
- Percent full load for engines
- Number of engines
- Horsepower of engines
- Number of fracturing stages
- Duration of each fracturing stage (hours)

A table on the reverse side of this letter shows the type of data we wish to collect.

We appreciate your assistance in this study. If you have any questions on the technical aspects of the study, please contact me at (919) 468-7902, or via email at stephen.treimel@erg.com. Completed surveys should be sent to my attention. Questions concerning the scope of this study or ERG's relationship with TCEQ may be directed to the TCEQ Project Manager, Michael Ege, at (512) 239-5706, or via email at Michael.Ege@tceq.texas.gov.

Sincerely,

Stephen Treimel, Environmental Scientist
Eastern Research Group, Inc.

Operator Name: [Insert Operator_Company_Name]
Basin and Counties: [Insert Basin_name] basin: [Insert counties_text]
Instructions: Provide the data listed below for up to ten separate well sites located in the counties listed above. To avoid biasing the survey results, we ask that you please select the well sites at random from all of the wells you worked on in this region in 2013.

Site #	County	Well type (oil or gas) [a]	Number of Engines	Horsepower of Engines	Percent Full Load for Engines (when active)	Number of Fracturing Stages	Duration of Each Fracturing Stage (hours)

[a] Does the Texas Railroad Commission consider this well a gas well (G) or an oil well (O)?

Completed surveys can be emailed to me at stephen.treimel@erg.com or printed and mailed to my attention at: Eastern Research Group, 1600 Perimeter Park Drive, Morrisville, NC 27560.

Attachment B
Mud Degassing Survey Letter

Dear [Insert Operator_Contact_Name], [Insert Operator_Contact_Title]

[Insert Operator_Company_Name] [Date]

Eastern Research Group (ERG), an independent research organization, is conducting a study on emissions from drilling mud degassing for the Texas Commission on Environmental Quality (TCEQ). The purpose of this study is to develop activity estimates for estimating emissions from mud degassing activities during well drilling for each of the oil and gas producing regions in Texas. The study results will assist the TCEQ in refining the Texas air emissions inventory.

Emissions from mud degassing are currently estimated by TCEQ using EPA default water-based mud emission factors from the Climate Registry Reporting Protocol and activity data from a 2012 Central States Air Resource Agencies (CenSARA) study. The purpose of this survey is to gather Texas-specific data on drilling mud usage, characteristics, and mud degassing activities so that TCEQ can refine its emissions estimates. To support this effort, the TCEQ is seeking information from Texas oil and gas drilling companies to assist in development of refined, county-specific equipment and usage data.

We are asking for your participation in this voluntary survey that will involve sharing information regarding the location, the type of well, the type of drilling mud used, the number of drilling days per well, and any control equipment used. ***Individual wells and rigs do not need to be identified.*** The information your company provides will be used for statistical purposes only in order to develop county-level and basin-level estimates and will not be republished or disseminated for other purposes. **The information you provide will be held confidential.**

ERG will contact your company via phone to discuss this effort and collect any information you are willing to share. We are seeking basin-specific mud degassing emissions information for oil and gas wells drilled/recompleted in the [Insert Basin_name] [Insert counties_text] The specific information we are requesting for each well drilled or recompleted in 2013:

- County
- Well type (oil or gas)
- New well or recompletion
- Type of mud used (water- or oil-based)
- Number of drilling days per well
- Are emissions from degassing equipment controlled?

A table on the reverse side of this letter shows the type of data we wish to collect.

We appreciate your assistance in this study. If you have any questions on the technical aspects of the study, please contact me at (919) 468-7902, or via email at stephen.treimel@erg.com. Completed surveys should be sent to my attention. Questions concerning the scope of this study or ERG's relationship with TCEQ may be directed to the TCEQ Project Manager, Michael Ege, at (512) 239-5706, or via email at Michael.Ege@tceq.texas.gov.

Sincerely,

Stephen Treimel, Environmental Scientist
Eastern Research Group, Inc.

Operator Name: [Insert Operator_Company_Name]

Basin and Counties: [Insert Basin_name] [Insert counties_text]

Instructions: Provide the data listed below for up to ten separate well sites located in the basin/counties listed above. To avoid biasing the survey results, we ask that you please select the well sites at random from the wells drilled in this region in 2013.

Site #	County	Well type (oil or gas) [a]	New well or Recompletion	Type of mud used (water-based, oil-based, synthetic)	Number of drilling days	Are emissions from degassing equipment controlled? (Y/N)	Percent Control (%)

[a] Does the Texas Railroad Commission consider this well a gas well (G) or an oil well (O)?

Completed surveys can be emailed to me at stephen.treimel@erg.com or printed and mailed to my attention at: Eastern Research Group, 1600 Perimeter Park Drive, Morrisville, NC 27560.

Attachment C
Survey Results
(TCEQ Hydraulic Pump Engine Study Findings.xlsx)

Attachment D
Updated Oil and Gas Nonpoint Area Source Emissions Estimation Tool
(ERG Appendix E_2013 with updates to Basin information.xlsx)