Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost Effective Improvements

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1.0 EXECUTIVE SUMMARY

Natural gas production in the Barnett Shale region of Texas has increased rapidly since 1999, and as of June 2008, over 7700 oil and gas wells had been installed and another 4700 wells were pending. Gas production in 2007 was approximately 923 Bcf from wells in 21 counties. Natural gas is a critical feedstock to many chemical production processes, and it has many environmental benefits over coal as a fuel for electricity generation. Nevertheless, oil and gas production from the Barnett Shale can impact local air quality and release greenhouse gases into the atmosphere. The objective of this study was to investigate the emissions of air pollutants from oil and gas production in the Barnett Shale area, and to identify some cost-effective emissions control options.

An emissions inventory was developed for point sources involved in Barnett Shale activities, which are compressor engines and oil/condensate tanks. Emissions were also estimated for fugitive and intermittent sources, which include production equipment fugitives, well drilling and well completions, gas processing, and transmission fugitives. Pollutants analyzed included smog forming emissions (NOx and VOC), greenhouse gases, and air toxic compounds.

By 2009, emissions of smog forming compounds from the engines and tanks are expected to be about 260 tons per day. The engines, tanks, and fugitive and intermittent sources combined are expected to emit approximately 620 tons per day total of smog-forming compounds, substantially greater than the emissions from other sources in Dallas-Fort Worth area, such as the major airports or on-road motor vehicles. Emissions of air toxic compounds (like benzene and formaldehyde) from Barnett Shale activities will be approximately 33 tons per day. In addition, emissions of greenhouse gases like carbon dioxide and methane will be approximately 30,000 equivalent tons per day.

The oil and gas sector in the Barnett Shale is a significant source of air emissions in the north-central Texas area, comparable in magnitude to other major sources, including the airports and motor vehicles. Cost effective control strategies are readily available that can substantially reduce emissions, and in some cases, reduce costs for oil and gas operators.

2.0 BACKGROUND

2.1 Barnett Shale Natural Gas Production

The Barnett Shale is a productive geological formation for oil and gas that the Texas Railroad Commission (RRC) estimates to extend 5000 square miles in parts of at least 21 Texas counties. The productive region of the Barnett Shale has been designated as the Newark East Field, and large scale development of the natural gas resources in the field began in the late 1990's. Figure 1 shows the rapid and continuing development of natural gas from the Barnett Shale over the last 10 years.[1]

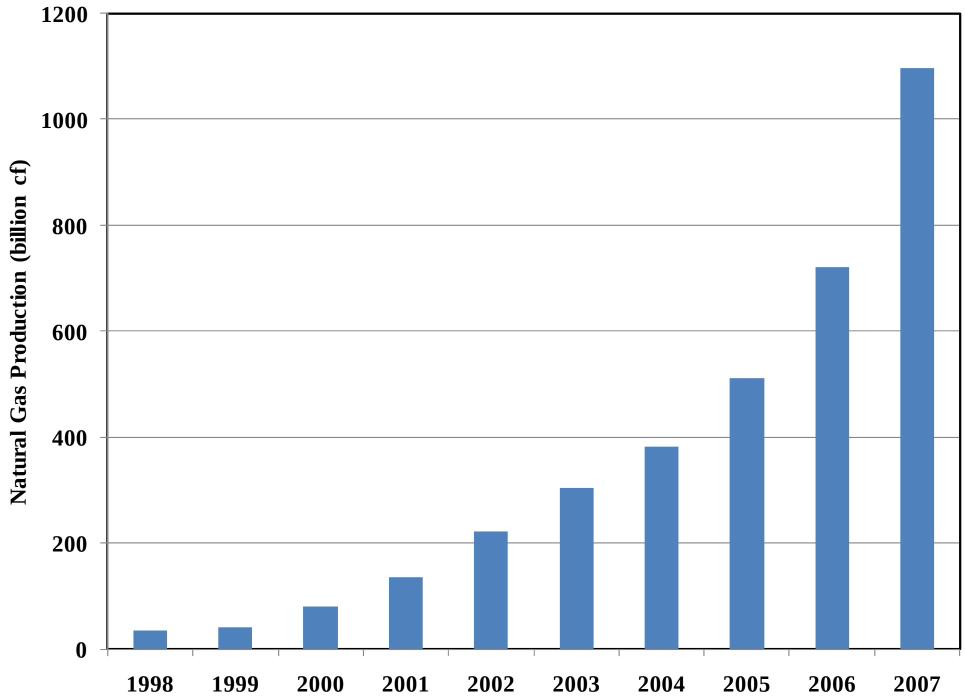


Figure 1. Barnett Shale Natural Gas Production, 1998-2007.

The issuance of new drilling permits has been following the upward trend of increasing natural gas production. The RRC issued 1112 well permits in 2004, 1629 in 2005, 2507 in 2006, 3657 in 2007, and they are on-track to issue over 4000 permits in 2008. The vast majority of the wells and permits are for natural gas production, but a small number of oil wells are also in operation or permitted, and some oil wells co-produce casinghead gas. As of June 2008, over 7700 wells had been registered with the RRC, and the permit issuance rates are summarized in Table 1-1.[1] Annual oil, gas, condensate, and casinghead gas production rates for 21 counties in and around the Barnett Shale area are shown in Table 1-2.[1] The majority of Barnett Shale wells and well permits are located in six counties around the city of Fort Worth: Tarrant, Denton, Wise, Parker, Hood, and Johnson Counties. Figure 2 shows the locations of wells and well permits in the Barnett Shale.[2]

The top three gas producing counties in 2007 were Johnson, Tarrant and Wise, and the top three condensate producing counties were Wise, Denton, and Parker.

Table 1-1. Barnett Shale Drilling Permits Issued, 2004-2008.(1)

year	new drilling permits
2004	1112
2005	1629
2006	2507
2007	3657
2008	4000+

Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.(1)

County	Gas Production (MCF)	Condensate (BBL)	Casinghead Gas (MCF)	Oil Production (BBL)
Johnson	282,545,748	28,046	0	0
Tarrant	246,257,349	35,834	0	0
Wise	181,577,163	674,607	6,705,809	393,250
Denton	168,020,626	454,096	934,932	52,363
Parker	80,356,792	344,634	729,472	11,099
Hood	32,726,694	225,244	40,271	526
Jack	16,986,319	139,009	2,471,113	634,348
Palo Pinto	12,447,321	78,498	1,082,030	152,685
Stephens	11,149,910	56,183	3,244,894	2,276,637
Hill	7,191,823	148	0	0
Erath	4,930,753	11,437	65,425	5,073
Eastland	4,129,761	130,386	754,774	259,937
Somervell	4,018,269	6,317	0	0
Ellis	1,715,821	0	17,797	10
Comanche	560,733	1,584	52,546	7,055
Cooke	352,012	11,745	2,880,571	2,045,505
Montague	261,734	11,501	3,585,404	1,677,303
Clay	261,324	12,046	350,706	611,671
Hamilton	162,060	224	0	237
Bosque	135,116	59	0	0
Kaufman	0	0	3,002	61,963

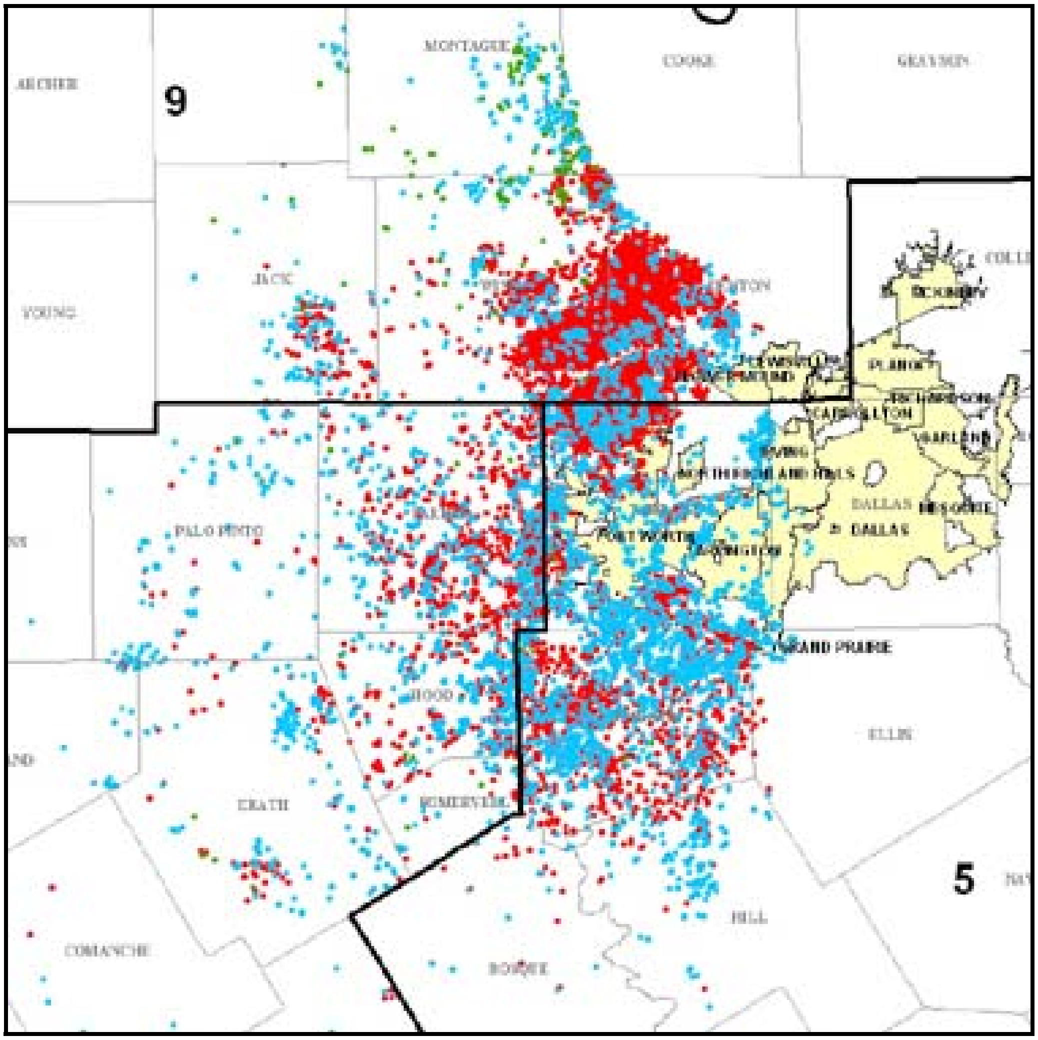


Figure 2. Well and Well Permit Locations in the Barnett Shale area (red = gas wells, green = oil wells, blue = permits. Major cities in yellow. RRC district 5, 7B, & 9 boundaries shown in black.)

2.2 Primary Emission Sources from Barnett Shale Oil and Gas Production

There are a variety of activities that potentially create air emissions during oil and gas production in the Barnett Shale area. Four of the counties where oil and gas production are ongoing (Tarrant, Denton, Parker, and Johnson) are part of the Dallas-Fort Worth nonattainment area for the national ambient air quality standard for ozone. Regulatory programs are different for some emission sources inside the nonattainment area compared to outside. The primary emission sources in the Barnett Shale oil and gas sector include compressor engine exhaust, oil and condensate tank vents, production well fugitives, well drilling and well completions, natural gas processing, and transmission fugitives. Figure 3 shows a schematic diagram of the major machinery and process units in the natural gas industry, and the major source categories are described in the following sections.[15]

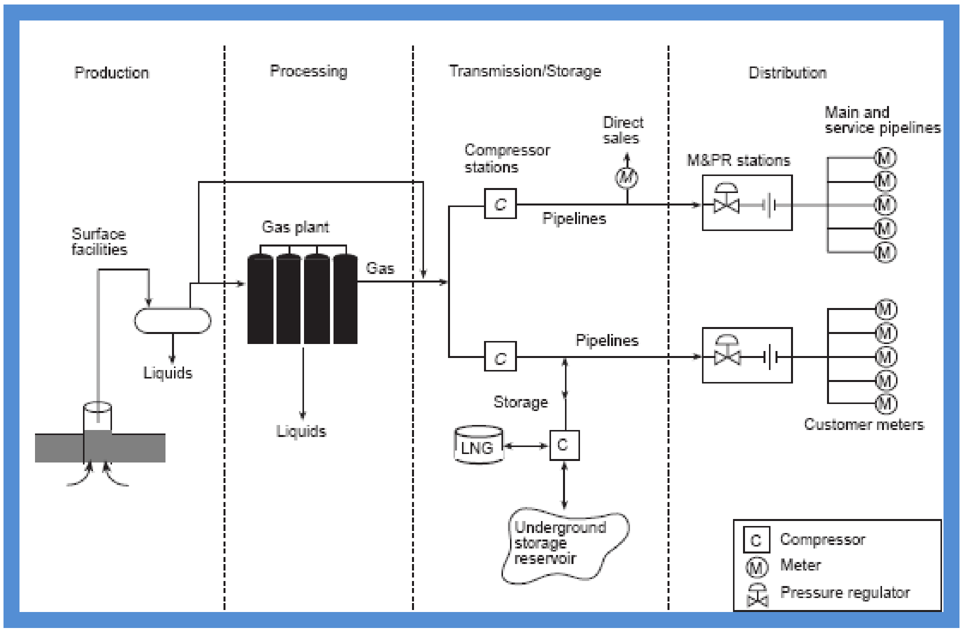


Figure 3. Major Units in The Natural Gas Industry From Wells to Customers. [15]

2.2.1 – Point Sources

i. Compressor Engines

Internal combustion engines are used to provide the power to run compressors that pressurize natural gas from wells to the pressure of lateral lines that collect the natural gas and direct it to larger pipelines. Engines are also used to power compressors that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions. Most of the engines driving compressors in the Barnett Shale area are between 100 and 500 hp in size, but some large engines of 1000+ hp are also used.

ii. Condensate and Oil Tanks

Fluids that are brought to the surface at Barnett Shale natural gas wells are a high-pressure mixture of natural gas, other gases, water, and hydrocarbon liquids. The high pressure mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from the water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. The hydrocarbon liquid is known as condensate. The condensate tanks at Barnett Shale wells are typically 10,000 to 20,000 gallons and hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. At oil wells, tanks are used to store crude oil on-site before the oil is transported to refiners. Like the condensate tanks, oil tanks can be sources of hydrocarbon vapor emissions to the atmosphere through tank vents.

2.2.2 – Fugitive and Intermittent Sources

i. Production Fugitive Emissions

Natural gas wells can contain a large number of individual components, including pumps, flanges, valves, gauges, pipe connectors, and other pieces. These components are generally intended to be tight, but leaks are not uncommon and some leaks can result in large emissions of hydrocarbons and methane to the atmosphere. The emissions from such leaks are called "fugitive" emissions. These fugitive emissions can be caused by routine wear, rust and corrosion, improper installation or maintenance, or overpressure of the gases or liquids in the piping. In addition to the unintended fugitive emissions, pneumatic valves which operate on pressurized natural gas leak small quantities of natural gas by design during normal operation. Natural gas wells, processing plants, and pipelines often contain large numbers of these kinds of pneumatic valves, and the accumulated emissions from all the valves in a system can be significant.

ii. - Well Drilling and Completions

Oil and gas drilling rigs require substantial power to drive drill bits to the depths of hydrocarbon deposits. In the Barnett Shale, this power is provided by transportable diesel engines, and operation of these engines generates exhaust from the burning of diesel fuel. In addition, subsurface pressures drive gas, hydrocarbon liquids, water, sand, and other materials to the surface after wells have been drilled to specified depth. Emissions of natural gas to the atmosphere can occur during the drilling process, and after the well is completed before the well bore is connected to permanent gas collecting hardware at a well site. The permanent hardware used at a gas well, including the piping, separator, and tanks, are not designed to handle the wet and abrasive flow that often comes to the surface upon well completion. Instead, the liquids/dirt/gas mixture is typically dumped into pits or tanks, and the gas is often vented or flared. The venting/flaring of the gas results in a loss of potential revenue and also in hydrocarbon and methane emissions to the atmosphere.

iii. Natural Gas Processing

Natural gas produced from wells is a mixture of a large number of gases and vapors. Well-head (a.k.a. wet or raw) natural gas is delivered to processing plants where much of the higher molecular weight hydrocarbons, water, nitrogen, and other compounds are removed, leaving behind a gas stream that is enriched in methane at a concentration of usually more than 80%.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. In addition to water, the glycol absorbant usually collects significant quantities of hydrocarbons, which can be emitted to the atmosphere when the glycol is regenerated with heat. The glycol dehydrators, pumps, and other machinery used in natural gas processing can release methane and hydrocarbons into the atmosphere from individual process units, as can the flanges, valves, and other fittings at the plants.

iv. Natural Gas Transmission Fugitives

Produced natural gas is transported from wells in mostly underground gathering lines which form networks that eventually collect gas from hundreds or thousands of well locations. Pipeline networks gradually increase in pipe diameter as the volume of gas transported increases. Natural gas from wells is transported in pipeline networks from wells to processing plants, storage formations, and/or the interstate pipeline network for eventual delivery to customers. Leaks from pipeline networks, from microscopic holes, corrosion, welds and other connections, blow and purge operations, and from the large number of pneumatic devices on the pipeline network can result in large emissions of methane and hydrocarbons into the atmosphere, and lost revenue producers.

2.3 Objectives

Barnett Shale oil and gas production can emit pollutants to the atmosphere which contribute to ozone and particulate matter smog, are known toxic chemicals, and contribute to climate change. The objectives of this study were to: (1) estimate emissions from Barnett Shale oil and gas production of volatile organic compounds, nitrogen oxides, hazardous air pollutants, methane, carbon dioxide, and nitrous oxide; (2) evaluate the current state of regulatory controls and engineering techniques used to control emissions from the oil and gas sector in the Barnett Shale; (3) summarize the state of the art and new ideas in emissions controls and determine their application to Barnett Shale activities; and (4) estimate the emissions reductions and cost effectiveness of implementation of state of the art and new ideas. Emission estimates were made for the most recent calendar year, 2007, as well as for the 2009 calendar year.

3.0 TECHNICAL APPROACH

3.1 Pollutants

Estimates were made of 2007 and 2009 emissions of smog forming, air toxic, and greenhouse gas compounds, including nitrogen oxides (NO_x), volatile organic compounds (VOCs), air toxic or a.k.a. hazardous air pollutants (HAPs), methane (CH_4), nitrous oxide (N_2O), and carbon dioxide (CO_2). Volatile organic compounds are generally carbon and hydrogen containing chemicals that exist in the gas phase or can evaporate and form vapors and that can react in the atmosphere to form ozone smog. Methane and ethane are specifically excluded from the definition of VOC because they react slower than the other VOC compounds to produce ozone. The hazardous air pollutants discussed in this report are a subset of the VOC compounds, and include those compounds that are known or believed to cause adverse human health effects. An example of a HAP compound is benzene, which is an organic compound known to contribute to the development of cancer.

Emissions of the greenhouse gases were aggregated as carbon dioxide equivalent tons (CO_2e) by combining CO_2, CH_4, and N_2O emissions, and scaling CH_4 tons by 21 and N_2O tons by 310 to account for their higher greenhouse gas potentials of these gases.(4) Emissions in 2009 were estimated by examining recent trends in Barnett Shale hydrocarbon production and extrapolating production out to 2009.

3.2 Hydrocarbon Production

Production rates in 2007 for oil, gas, casinghead gas, and condensate were obtained from the Texas Railroad Commission for each county in the Barnett Shale area.(5) County-level production rates were used to determine the amount of Barnett Shale production from counties inside and outside the DFW nonattainment area. Production rates in 2009 were predicted by plotting production rates from 2000-2007 and fitting a 2^{nd}-order polynomial to the production rates via the least-squares method and extrapolating out to 2009.

3.3 Compressor Engines Emission Factors and Emission Estimates

i. Engines Identified in 2007 Survey in the DFW Nonattainment Area

Large natural gas compressor engines, located primarily at compressor stations and also some at well sites, have typically reported emissions to the Texas Commission on Environmental Quality (TCEQ) in annual Point Source Emissions Inventory (PSEI) reports. However, prior to 2007, many engines in the Barnett Shale area had not reported emissions to the PSEI and their contribution to regional air quality was unknown. In late 2007, the TCEQ conducted an engine survey for counties in the DFW nonattainment area, and operators reported engine counts, engine sizes, NO_x emissions, and other data to TCEQ. Data summarized by TCEQ from the survey was used for this report to estimate emissions from natural gas compressor engines in the Barnett Shale area that had previously not reported emissions into the annual PSEI.(6) Data obtained from TCEQ included total operating engine power in the nonattainment area, grouped by rich vs. lean burn engines, and also grouped by engines smaller than 50 hp, between 50 to 500 hp and those larger than 500 hp.

Regulations adopted by TCEQ and scheduled to take effect in early 2009 will limit NO_x emissions in the DFW non-attainment area for engines larger than 50 horsepower.(7) Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. For this report, emissions in 2009 from the engines in the nonattainment area subject to the new rules were estimated assuming 97% compliance with the upcoming rules and a 3% noncompliance factor for engines continuing to emit at pre-2009 levels.

Emissions for 2007 were estimated using NO_x emission factors provided by operators to TCEQ in the 2007 survey.(6) Emissions of VOCs were determined using TCEQ-determined emission factors, and emissions of HAPs, CH_4, and CO_2 were determined using emission factors from EPA's AP-42 document.(8,9) In AP-42, EPA provides emission factors for numerous HAP compounds created during incomplete fuel combustion, but for this report only those factors which were judged by EPA to be of high quality, "A" or "B" ratings, were used to estimate emissions. Emission factors for N_2O were from a greenhouse gas emissions inventory report issued by the American Petroleum Institute.(10)

Beginning in 2009, many engines subject to the new NO_x limits are expected to reduce their emissions with the installation of non-selective catalytic reduction units (NSCR), a.k.a. three-way catalysts. NSCR units are essentially modified versions of the "catalytic converters" that are standard equipment on every gasoline-engine passenger vehicle in the U.S.

A likely co-benefit of NSCR installation will be the simultaneous reduction of VOC, HAP, and CH_4 emissions. Emissions from engines expected to install NSCR units were determined using a 75% emissions reduction factor for VOC, HAPs, and CH_4. Conversely, NSCR units are known to increase N_2O emissions, and N_2O emissions were estimated using a 3.4x factor increase over uncontrolled emissions.(10) Table 2 summarizes the emission factors used to calculate emissions from the compressor engines identified in the 2007 survey.

Table 2. Emission Factors for Engines Identified in the DFW 2007 Engine Survey

Table 2-1. Emission Factors for 2007 Emissions

engine type	engine size	NO_x (g/hp-hr)[a]	VOC (g/hp-hr)[b]	HAPs (g/hp-hr)[c]	CH_4 (g/hp-hr)[d]	CO_2 (g-hp-hr)[e]	N_2O (g-hp-hr)[f]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	13.6	0.43	0.088	0.89	424	0.0077
rich	>500	0.9	0.43	0.088	0.89	424	0.0077
lean	<500	6.2	1.6	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

Table 2-2. Emission Factors for 2009 Emissions

engine type	engine size	NO_x (g/hp-hr)[i]	VOC (g/hp-hr)[j]	HAPs (g/hp-hr)[k]	CH_4 (g/hp-hr)[l]	CO_2 (g-hp-hr)[m]	N_2O (g-hp-hr)[n]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	0.5	0.11	0.022	0.22	424	0.026
rich	>500	0.5	0.11	0.022	0.22	424	0.026
lean[g]	<500	0.62	1.6	0.27	4.8	424	0.012
lean[h]	<500	0.5	1.6	0.27	4.8	424	0.012
lean[g]	>500	0.7	1.6	0.27	4.8	424	0.012
lean[h]	>500	0.5	1.6	0.27	4.8	424	0.012

notes:
a: email from TCEQ to SMU, August 1, 2008, summary of results from 2007 engine survey (reference 6).
b: email from TCEQ to SMU, August 6, 2008 (reference 8).
c: EPA, AP-42, quality A and B emission factors; rich engine HAPs = benzene, formaldehyde, toluene; lean engine HAPs = acetaldehyde, acrolein, xylene, benzene, formaldehyde, methanol, toluene, xylene (reference 9).
d: EPA, AP-42 (reference 9).
e: EPA, AP-42 (reference 9).
f: API Compendium Report (reference 10).
g: TCEQ regulatory limit for engines moved or installed before June 2007 (reference 7).
h: TCEQ regulatory limit for engines moved or installed after June 2007 (reference 7).
i: rich (<50) factor from email from TCEQ to SMU, August 1, 2008 (reference 6); rich (50-500), rich (>500), lean (<500, post-2007), lean (>500, pre-2007), and lean (>500, post-2007) from TCEQ regulatory limits (reference 6); lean (<500, pre-2007) estimated with 90% control.
j: rich (<50) from email from TCEQ to SMU (reference 8); rich (50-500) and rich (>500) estimated with 75% NSCR control VOC co-benefit; lean EFs from email from TCEQ to SMU (reference 8).
k: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.
l: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.
m: EPA, AP-42 (reference 9).
n: API Compendium Report (reference 10); rich (50-500) and rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate.

Annual emissions from the engines identified in the 2007 survey were estimated using the pollutant-specific emission factors from Table 1 together with Equation 1,

$$M_{E,i} = 1.10E\text{-}06 * E_i * P_{cap} * F_{hl} \quad (1)$$

where $M_{E,i}$ was the mass emission rate of pollutant *i* in tons per year, E_i was the emission factor for pollutant *i* in grams/hp-hr, P_{cap} is installed engine capacity in hp, and F_{hl} is a factor to adjust for annual hours of operation and typical load conditions.

Installed engine capacity in 2007 was determined for six type/size categories using TCEQ estimates from the 2007 engine survey - two engine types (rich vs lean) and three engine size ranges (<50, 50-500, >500 hp) were included.[6] TCEQ estimates of the average engine sizes and the numbers of engines in each size category were used to calculate the installed engine capacity for each category, as shown in Table 3. The F_{hl} factor was used to account for typical hours of annual operation and average engine loads. A F_{hl} value was 0.5 was used for this study, based on 8000 hours per year of average engine operation (8000/8760 = 0.91) and operating engine loads of 55% of rated capacity, giving an overall hours-load factor of 0.91x 0.55 = 0.5.[11]

Table 3. Installed Engine Capacity in 2007 DFW Engine Survey by Engine Type and Size

engine type	engine size (hp)	number of engines[q]	typical size[q] (hp)	installed capacity[r] (hp)
rich	<50	12	50	585
rich	50-500	724	140	101,000
rich	>500	200	1400	280,000
lean[o]	<500	14	185	2540
lean[p]	<500	13	185	2400
lean[o]	>500	103	1425	147,000
lean[p]	>500	103	1425	147,000

notes:
o: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
p: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
q: rich (<50) installed capacity based on HARC October 2006 H68 report which found that small rich burn engines comprise no more than 1% of engines in East Texas; rich (50-500) and rich (>500) installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6); lean burn installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6) along with RRC data suggesting that 50% of engines in 2009 will be subject to the post-June 2007 NOx rule.
r: installed capacity = number of engines x typical size

ii. Engines Reporting to the TCEQ Point Source Emissions Inventory (PSEI)

In addition to the engines identified in the 2007 TCEQ survey of the DFW nonattainment area, many other engines exist in the Barnett Shale area. These include engines both inside and outside the DFW nonattainment area that had already been reporting annual emissions to TCEQ in the PSEI, which are principally large engines at compressor stations as well as some large well engines.(12)

Emissions of NO_x from large engines in the DFW nonattainment area that were reporting to the TCEQ PSEI were obtained from the Year 2006 PSEI, the most recent calendar year available.(12) Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production from 2006-2009. For NO_x emissions in 2006 and 2007, an average emission factor of 0.9 g/hp-hr was obtained from TCEQ.(8) Emissions in 2009 were adjusted by accounting for the 0.5 g/hp-hr TCEQ regulatory limit scheduled to take effect in early 2009.(7)

Unlike NO_x emission, emissions of VOC were not taken directly from the PSEI. Estimates of future VOC emissions required accounting for the effects that the new TCEQ engine NO_x limits will have on future VOC emissions. A compressor engine capacity production factor of 205 hp/(MMcf/day) was obtained from TCEQ that gives a ratio of installed horsepower capacity to the natural gas production. The 205 hp/(MMcf/day) factor was based on previous TCEQ studies of gas production and installed large engine capacity. The factor was used with 2006 gas production values to estimate installed PSEI engine capacity for each county in the Barnett Shale area.(8) Engine capacity was divided between rich burn engines smaller and larger than 500 hp, and lean burn engines. To estimate 2009 emissions, rich burn engines smaller than 500 hp are expected to have NSCR units by 2009 and get 75% VOC, HAP, and CH_4 control. Table 4 summarizes the VOC, HAP, and greenhouse gas emission factors used for the PSEI engines in DFW. Table 5 summarized the estimates of installed engine capacity for each engine category.

Table 4. VOC, HAP, GHG Emission Factors for PSEI Engines in DFW NAA

Table 4-1. Emission Factors for 2007 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

Table 4-2. Emission Factors for 2009 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.11	0.022	0.22	424	0.026
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

notes:
s: email from TCEQ to SMU, August 6, 2008; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 8).
t: EPA, AP-42 (reference 9); 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).
u: EPA, AP-42 (reference 9) ; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).
v: EPA, AP-42 (reference 9).
w: API Compendium Report; 2007 rich (>500), and 2009 rich (>500) and 2009 rich (<500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 5. Installed Engine Capacity in 2007 for PSEI Engines in DFW NAA

engine type	engine size (hp)	installed capacity (%)[x]	installed capacity (hp)[y]
rich	<500	0.14	59,500
rich	>500	0.52	221,000
lean	all	0.34	144,000

notes:
x: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
y: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

Emissions of NO_x from large engines outside the DFW nonattainment area reporting to the TCEQ were obtained from the 2006 PSEI.[(12)] Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production from 2006-2009. Unlike engines inside the NAA, the engines outside the NAA are not subject to the new engine rules scheduled to take effect in 2009, and thus new NSCR installations are not required as a result of the new rules.

Emissions of VOC, HAPs, and greenhouse gases for engines outside the DFW nonattainment area were not obtained from the 2006 PSEI. A process similar to the one used to estimate emissions from large engines inside the NAA was used, whereby the TCEQ compressor engine capacity production factor, 205 hp/(MMcf/day), was used along with actual 2007 production rates to estimate total installed engine capacity as well as installed capacity in each county for different engine categories. Pollutant-specific emission factors were applied to the capacity estimates for each category to estimate emissions. Table 6 summarizes the emission factors used to estimate emissions from engines in the PSEI outside the DFW nonattainment area. The engine capacities used to estimate emissions are shown in Table 7.

Table 6. VOC, HAP, GHG Emission Factors for PSEI Engines Outside DFW NAA

engine type	engine size	VOC (g/hp-hr)[z]	HAPs (g/hp-hr)[aa]	CH_4 (g/hp-hr)[aa]	CO_2 (g-hp-hr)[bb]	N_2O (g-hp-hr)[cc]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

notes:
z: email from TCEQ to SMU, August 6, 2008; 75% control applied to rich (>500) engines (reference 8).
aa: EPA, AP-42; 75% control applied to rich (>500) engines (reference 9).
bb. EPA, AP-42 (reference 9).
cc. API Compendium Report; rich (>500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 7. Installed Engine Capacity in 2007 for PSEI Engines Outside DFW NAA

engine type	engine size (hp)	installed capacity (%)[dd]	installed capacity (hp)[ee]
rich	<500	0.14	17,000
rich	>500	0.52	62,000
lean	all	0.34	41,000

notes:
dd: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
ee: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iii. Engines Outside the DFW Nonattainment Area Not Reporting to the PSEI

The PSEI only contains emissions from a fraction of the Barnett Shale compressor engines outside the DFW nonattainment area, principally the larger engines with emissions above the PSEI reporting thresholds. The 2007 engine survey of engines inside the nonattainment area demonstrated that the PSEI does not include a substantial fraction of compressor engine emissions. Most of the missing engines in the DFW NAA were units with emissions below the reporting thresholds, but the combined emissions from large numbers of these engines can be substantial.

The results of the 2007 survey indicated that there were approximately 680,000 hp of installed engine capacity in the DFW nonattainment area not previously reporting to the PSEI.[6] Natural gas and casinghead gas production from nonattainment counties in 2007 was approximately 1,000 Bcf , and a "non-PSEI" compressor engine capacity production factor of 226 hp/(MMcf/day) can thus be determined for the Barnett Shale. This production factor was used along with 2007 gas production rates from the attainment counties to estimate non-PSEI engine emissions in the attainment counties. The new production factor accounts for the fact that attainment counties likely contain previously unreported engine capacity in the same proportion to the unreported engine capacity that was identified during the 2007 engine survey inside the nonattainment area. Without a detailed engine survey in the attainment counties of the same scope as the 2007 survey performed in the nonattainment counties, use of the non-PSEI production factor provides a way to estimate emissions from engines not yet in state or federal inventories. The estimated capacity of non-PSEI reporting engines in the attainment counties of the Barnett Shale was estimated by this method to be 132,000 hp. Emission factors used to estimate emissions from these engines, and the breakdown of total installed engine capacity into engine type and size categories, are shown in Tables 8 and 9.

Table 8. Emission Factors for Non-PSEI Engines Outside DFW NAA

engine type	engine size	NO_x (g/hp-hr)[ff]	VOC (g/hp-hr)[gg]	HAPs (g/hp-hr)[hh]	CH_4 (g/hp-hr)[hh]	CO_2 (g-hp-hr)[ii]	N_2O (g-hp-hr)[jj]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	13.6	0.43	0.088	0.89	424	0.0077
rich	>500	0.9	0.11	0.022	0.22	424	0.026
lean	<500	6.2	1.6	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

notes:
ff: email from TCEQ to SMU, August 1, 2008 (reference 6).
gg: email from TCEQ to SMU, August 6, 2008; rich (>500) based on 75% control (reference 8).
hh: EPA, AP-42; rich (>500) based on 75% control (reference 9).
ii: EPA, AP-42 (reference 9).
jj: API Compendium Report; rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 9. Installed Engine Capacity for Non-PSEI Engines Outside NAA by Engine Type and Size

engine type	engine size (hp)	installed capacity (%)	installed capacity (hp)
rich	<50	0.01	110
rich	50-500	15	20,000
rich	>500	41	55,000
lean	<500	0.73	970
lean	>500	43	57,000

3.2 - Condensate and Oil Tanks Emission Factors and Emission Estimates

Condensate and oil tanks can be significant emitters of VOC, methane, and HAPs. A report was published in 2006 by URS Corporation which presented the results of a large investigation of emissions from condensate and oil tanks in Texas.[14] Tanks were sampled from 33 locations across East Texas, including locations in the Barnett Shale area. Condensate tanks in the Barnett Shale were sampled in Denton and Parker Counties, and oil tanks were sampled in Montague County. The results from the URS investigation were used for this study to calculate Barnett Shale-specific emission factors for VOC, methane, HAPs, and CO_2. The HAPs identified in the URS investigation included n-hexane, benzene, trimethylpentane, toluene, ethylbenzene, and xylene. The emission factors used to calculate emissions from Barnett Shale condensate and oil tanks are shown in Table 10.

Table 10. Condensate and Oil Tank Emission Factors for the Barnett Shale.

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	48	3.7	5.6	0.87
oil	6.1	0.25	0.84	2.7

Emissions for 2007 were calculated for each county in the Barnett Shale area with condensate and oil production rates from the RRC.[5] Emissions for 2009 were estimated with the extrapolated 2000-2007 production rates for the year 2009. Emissions were calculated with Equation 2,

$$M_{T,i} = E_i * P_c / 2000 \qquad (2)$$

where $M_{T,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/bbl, and P_c was the production rate of condensate or oil.

3.3 - Production Fugitive Emission Factors and Emission Estimates

Fugitive emissions from production wells vary from well to well depending on many factors, including the tightness of casing heads and fittings, the age and condition of well components, and the numbers of components per well. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[15] Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Production fugitives, excluding emissions from condensate tanks which are covered in another section of this report, were estimated by the GRI/EPA study to be approximately 20% of total fugitives, or 0.28% of gross production.

Production fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.28% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with a raw natural gas composition from a previous study.[16] HAPs in raw natural gas include n-hexane, benzene, and toluene. Volume emissions were converted to mass emissions with a density of 0.07056 lb/scf. Table 11 presents the production fugitives emission factors.

Table 11. Production Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
87	3.7	77	3.9

Emissions were calculated with Equation 3,

$$M_{F,i} = E_i * P_g / 2000 \qquad (3)$$

where $M_{F,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. In the raw gas, the chemical composition on a mass basis was approximately 40% CH_4, 45% VOC, 1.9% HAPs, and 2% CO_2.

3.4 - Well Drilling Engines and Well Completions Emission Factors and Emission Estimates

Given the short period of time during a year that drilling occurs at a well site before production begins, emissions from well drilling engines were expected to be relatively minor compared to the compressor engines, production fugitives, condensate tanks, and other sources that vent to the atmosphere almost continuously. Nonetheless, to examine the magnitude of drilling engine emissions, an emission estimate was performed for well drilling engines. Data from an August 2006 study of well drilling operations in New Mexico was used to develop emission factors, based on the average consumption of approximately 4900 gallons of diesel per well drilled, a BSFC of 0.45 lbs diesel/hp-hr, and AP-42 diesel engine emission factors.(9,17)

In addition to emissions from drilling rig engines, previous studies have examined emissions of natural gas during well completions. These studies include one by the Williams gas company, which estimated that a typical well completion could vent 24,000 Mcf of natural gas.(18) A report by the EPA Natural Gas Star program estimated that 3000 Mcf could be produced from typical well completions.(19) A report by ENVIRON published in 2006 describes emission factors used in Wyoming and Colorado to estimate emissions from well completions, which were equivalent to 1000 to 5000 Mcf natural gas/well.(20) Another report published in the June 2005 issue of the Journal of Petroleum Technology estimated that well completion operations could produce 7,000 Mcf. (21) Unless companies bring special equipment to the well site to capture the natural gas and liquids that are produced during well completions, these gases will be vented to the atmosphere or flared.

With the lack of specific information about well completion emissions from Barnett Shale wells, the median value of 5000 Mcf/well from all the other identified studies was used to estimate well drilling and completion natural gas production in the Barnett Shale. A control efficiency of 90% was applied to this estimate, to account for the use of flares to control emissions of natural gas during well completions, and the use of "green completions" at some wells which capture methane and VOC emissions, giving a final emission factor of 500 Mcf/well. Properly-operated flares can operate at greater than 90% control, but variability in control efficiency is likely across the large numbers of well completions in the basin. In addition, some natural gas is vented without flaring (0% control) for periods of time during drilling, completion, and well clean-out operations. The 500 Mcf/well is most likely a conservatively (low) estimate of emissions, and it is possible that emissions from well drilling and completions are higher than is estimated in this report. Without site-specific emission factors, however, the use of a conservative emission factor prevents gross overestimates of emissions from this category of activities.

The number of completed gas wells reporting to the RRC were plotted for the Feb. 2004 – Feb. 2008 time period.[22] A least-squares regression line was fit to the data, and the slope of the line provides the approximate number of new completions every year during this time period. A value of 1042 completions/year was relatively steady throughout the 2004-2008 time period (linear R^2 = 0.9915). Emissions in 2007 and 2009 from well completions were estimated using 1000 well completions/year for each year. Emission estimates were prepared for the entire Barnett Shale area, as well as inside and outside the DFW NAA. The data from 2004-2008 show that new well completions are being installed at a rate of approximately 740 per year in the DFW nonattainment area, and 302 per year outside the nonattainment area, and that the rate of new completions has been steady since 2004. Emissions of VOC, HAPs, CH_4, and CO_2 were estimated using the same raw natural gas composition used for production fugitive emissions.[16]

3.5 - Processing Fugitives Emission Factors and Emission Estimates

Fugitive emissions from natural gas processing will vary from processing plant to processing plant, depending on the age of the plants, whether they are subject to federal rules such as the NSPS Subpart KKK requirements, the chemical composition of the gas being processed daily, the processing capacity of the plants, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[15] Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Processing fugitives, excluding compressor engine emissions which were previously addressed in this report, were estimated to be approximately 9.7% of total fugitives, or 0.14% of gross production.

Processing fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.14% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with a raw natural gas composition.[16] Volume emissions were converted to mass emissions with a raw natural gas density of 0.07056 lb/scf. Table 12 presents the processing fugitives emission factors.

Table 12. Processing Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
43	1.8	38	1.9

Processing fugitive emissions were calculated with Equation 4,

$$M_{P,i} = E_i * P_g / 2000 \tag{4}$$

where $M_{P,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas.

3.6 - Transmission Fugitives Emission Factors and Emission Estimates

Fugitive emissions from the transmission of natural gas will vary with distance and pipeline factors, depending on the pressure of the pipeline, the integrity of the piping, fittings, and valves, the chemical composition of the gas being transported, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.(15) Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Transmission fugitives, excluding compressor engine exhaust emissions which were previously addressed in this report, were estimated to be approximately 33% of total fugitives, or 0.46% of gross production. Transmission includes the movement of natural gas from the wells to processing plants, and the processing plants to compressor stations. It does not include flow past the primary metering and pressure regulating (M&PR) stations and final distribution lines to customers. Final distribution of gas produced in the Barnett Shale can happen anywhere in the North American natural gas distribution system, and fugitive emissions from these lines are beyond the scope of this report.

Transmission fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.46% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with a pipeline quality natural gas composition from a previous study.(16) HAPs are present in small quantities in pipeline natural gas and include n-hexane and benzene. Volume emissions were converted to mass emissions with a density of 0.0457 lb/scf. Table 13 presents the transmission fugitives emission factors.

Table 13. Transmission Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
12	0.3	186	2.7

Transmission fugitive emissions were calculated with Equation 5,

$$M_{tr,i} = E_i * P_g / 2000 \qquad (4)$$

where $M_{tr,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas.

4.0 RESULTS

4.1 Point Souces

i. Compressor Engines

Emissions from compressor engines in the Barnett Shale area are summarized in Table 14. Results indicate that engines are significant sources of ozone and particulate matter precursors NO_x and VOC, with 2007 emissions estimated as 67 tpd. Emissions of NO_x are expected to fall 50% from 32 to 16 tpd for engines in the Dallas-Fort Worth nonattainment area (DFW NAA) because of regulations scheduled to take effect in 2009 and the installation of NSCR units on many engines. Reductions greater than 50% are unlikely because of the growth in natural gas production. For engines in the attainment area (AA) counties, NO_x emissions will rise from 20 tpd to 31 tpd because of the projected growth in natural gas production and the fact that engines in these counties are not subject to the 2009 engine regulations.

Emissions of volatile organic compounds are expected to increase from 15 to 21 tpd from 2007 to 2009, because of increasing natural gas production. The 2009 engine regulations do have the effect of reducing VOC emissions from some engines, but growth in production compensates for the reductions and VOC emissions from engines as a whole increase.

HAP emissions, which include toxic compounds such as formaldehyde and benzene, are expected to increase from 2.7 to 3.6 tpd from 2007 to 2009.

Greenhouse gas emissions from compressor engines are shown in Table 15. Emissions in 2007 as carbon dioxide equivalent tons were approximately 8900 tpd, and emissions are estimated to increase to nearly 14,000 tpd by 2009. Carbon dioxide contributed the most to the greenhouse gas emissions, accounting for approximately 90% of the CO_2 equivalent tons. The methane and nitrous oxide contributions to greenhouse gases were smaller for the engines than for other sources reviewed in this report.

Table 14. Emissions from Compressor Engines.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
DFW NAA Engines	32	13	2.2	35	7261	16	17	2.9	49	11294
AA Engines	20	2.6	0.45	7.4	1649	31	4.0	0.70	12	2583
Barnett Shale Engines Total	**52**	**15**	**2.7**	**43**	**8910**	**47**	**21**	**3.6**	**61**	**13877**

Table 15. Greenhouse Gas Emissions from Compressor Engines.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	CO2	CH4	N2O	CO2e	CO2	CH4	N2O	CO2e
DFW NAA Engines	6455	35	0.20	7261	10112	49	0.28	11294
AA Engines	1475	7.4	0.062	1649	2310	12	0.10	2583
Barnett Shale Engines Total	**7930**	**43**	**0.26**	**8910**	**12422**	**61**	**0.38**	**13877**

ii. Oil and Condensate Tanks

Emissions from condensate and oil tanks are shown in Table 16. Emissions of VOCs from the tanks were 124 tpd in 2007, and the number is expected to increase to 194 tpd in 2009. HAP emissions were also substantial from the tanks, with 2007 emissions of 9.5 tpd and 2009 emissions of 14.9 tpd. Greenhouse gas emissions from the tanks are near entirely from CH_4, with a small contribution from CO_2. In carbon dioxide equivalent tons, greenhouse gas emissions were 308 tpd in 2007 which will increase to 483 tpd in 2009.

Table 16. Emissions from Condensate and Oil Tanks.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
DFW NAA Tanks	57	4.4	6.7	142	90	6.9	10	222
AA Tanks	66	5.1	7.8	166	104	8.0	12	261
Barnett Shale Tanks Total	**124**	**9.5**	**15**	**308**	**194**	**14.9**	**23**	**483**

4.2 Fugitives and Intermittent Sources

i. Production Fugitives

Emissions from fugitive sources at Barnett Shale production sites are shown in Table 17. Production fugitives are significant sources of VOC and HAP emissions, with VOC emissions expected to grow from 2007 to 2009 from 132 to 206 tpd, and HAP emissions expected to grow from 5.5 to 8.6 tpd. Production fugitives are also very large sources of methane emissions, leading to large CO_2 equivalent greenhouse gas emissions. Greenhouse gas emissions were 2442 tpd CO_2 equivalent in 2007, and are estimated to be 3825 tpd in 2009.

Table 17. Emissions from Production Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
DFW NAA Production Fugitives	91	3.8	80	1681	142	6.0	125	2634
AA Production Fugitives	41	1.7	36	760	64	2.7	57	1191
Barnett Shale Production Fugitives Total	**132**	**5.5**	**116**	**2442**	**206**	**8.6**	**182**	**3825**

ii. Well Drilling and Well Completions

Emissions from well drilling and well completion activities are shown in Table 18. Emissions from well drilling engines were a comparatively small portion of emissions from this category, accounting for 3.3 tpd NO_x, 0.27 tpd of VOC, and 128 tpd of CO_2. Most of the emissions were from natural gas entering the atmosphere during well completion activities, producing approximately 23 tpd of VOC, 1 tpd of HAPs, and 550 tpd of CO_2 equivalent emissions. Based on 2000-2007 drilling trends, approximately 70% of the well drilling and completion emissions for 2009 will be coming from counties in the DFW NAA, with the remaining 30% coming from counties outside the NAA.

Table 18. Emissions from Well Drilling and Well Completions.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
DFW NAA Well Drilling and Well Completion	2.4	16	0.7	14	388	2.4	16	0.7	14	388
AA Well Drilling and Well Completions	0.97	6.6	0.27	5.8	159	1.0	6.6	0.27	5.8	159
Barnett Shale Well Drilling and Completions Emissions Total	**3.3**	**23**	**0.9**	**20**	**547**	**3.3**	**23**	**0.9**	**20**	**547**

iii. Natural Gas Processing

Processing of Barnett Shale natural gas results in significant emissions of VOC, HAPs, and greenhouse gases, which are summarized in Table 19. Emissions of VOC were 65 tpd in 2007 and are expected to increase to 101 tpd by 2009. HAPs emissions were 2.7 tpd in 2007 and will increase to 4.3 tpd in 2009. Greenhouse gas emissions, resulting from fugitive releases of methane, were approximately 1200 tpd in 2007 and will be approximately 1900 tpd in 2009.

Table 19. Emissions from Natural Gas Processing.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
DFW NAA Processing Emissions	45	1.9	39	827	70	2.9	62	1296
AA Processing Emissions	20	0.8	18	374	32	1.3	28	586
Barnett Shale Processing Emissions Total	**65**	**2.7**	**57**	**1201**	**101**	**4.3**	**89**	**1882**

iv. Transmission Fugitives

Transmission of Barnett Shale natural gas results in significant emissions of methane and VOC, with methane emissions from transmission being larger than any of the other source categories. Emissions of VOC in 2007 from transmission were approximately 18 tpd in 2007 and are estimated to be 28 tpd in 2009. Emissions of HAPs are comparatively smaller, at less than 1 tpd in both 2007 and 2009. Greenhouse gas emissions from methane fugitives result in emissions of approximately 5900 tpd in 2007 and 9200 tpd in 2009. Emissions are summarized in Table 20.

Table 20. Emissions from Natural Gas Transmission Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
DFW NAA Transmission Fugitives	13	0.35	192	4038	20	0.55	301	6326
AA Transmission Fugitives	5.7	0.16	87	1826	8.9	0.25	136	2860
Barnett Shale Transmission Fugitives Total	**18**	**0.51**	**279**	**5864**	**28**	**0.79**	**437**	**9187**

4.3 All Sources Emission Summary

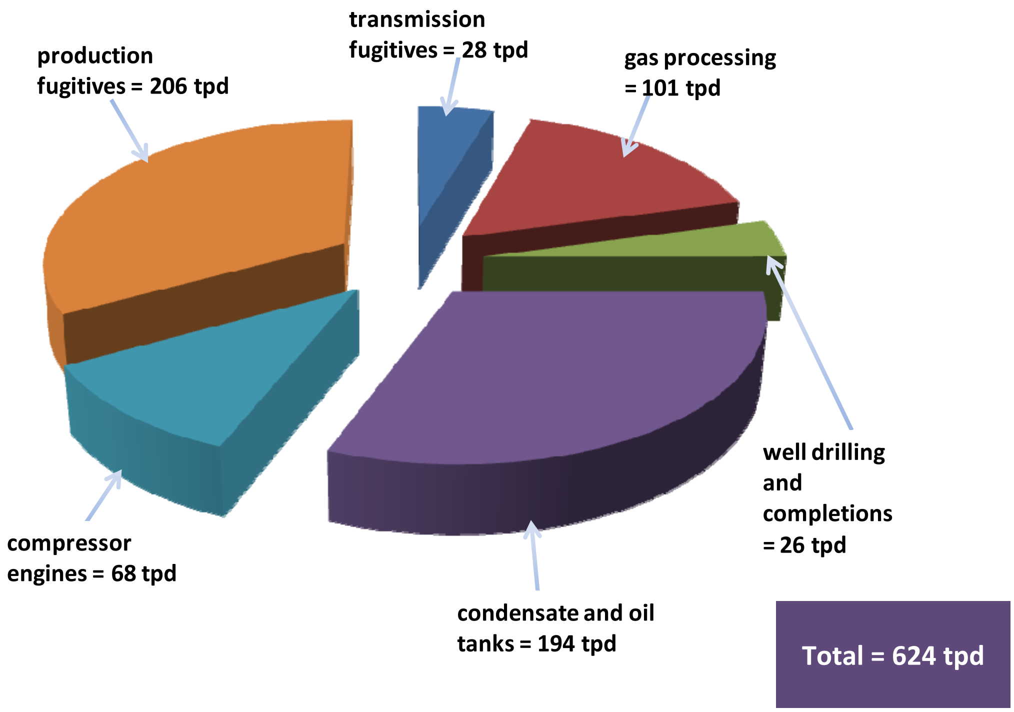
Emissions from all source categories in the Barnett Shale are summarized in Table 21. Total daily emissions for 2009 of ozone and particulate precursors NO_x and VOC were approximately 620 tpd in 2009. Greenhouse gas emissions were almost evenly divided between compressor engine emissions (47% of 2009 CO_2e), and emissions from all other source categories (53% of 2009 CO_2e). Total daily greenhouse gas emissions were projected to be approximately 30,000 tpd for 2009. The compressor engine greenhouse gas contribution was dominated by carbon dioxide, while the greenhouse gas contribution from all other sources was mostly methane. Emissions of HAPs were significant from Barnett Shale, with emissions in 2007 of 22 tpd, growing to 33 tpd in 2009.

Table 21. Emissions Summary for All Source Categories.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engines	52	15	2.7	43	8910	47	21	3.6	61	13877
Condensate and Oil Tanks	0	124	10	15	308	0	194	15	23	483
Production Fugitives	0	132	5.5	116	2442	0	206	8.6	182	3825
Well Drilling and Completions	3.3	23	0.95	20	547	3.3	23	0.95	20	547
Gas Processing	0	65	2.7	57	1201	0	101	4.3	89	1882
Transmission Fugitives	0	18	0.51	279	5864	0	28	0.79	437	9187
Total Daily Emissions (tpd)	**55**	**376**	**22**	**529**	**19272**	**51**	**573**	**33**	**812**	**29800**

Emissions of nitrogen oxides from oil and gas production in the Barnett Shale were dominated by emissions from compressor engines, with a smaller contribution from well drilling engines. Emissions of volatile organic compound emissions were expected from all source categories in the Barnett Shale, some from incomplete fuel combustion products, but the high majority from condensate tank vents and from fugitive emissions which contain significant quantities of VOC compounds. Figure 4 presents the combined emissions of NO_x and VOC from all source categories in the Barnett Shale.

Figure 4. Emissions of Ozone & PM Precursors (NO_x and VOC) in 2009 from Barnett Shale Sources.



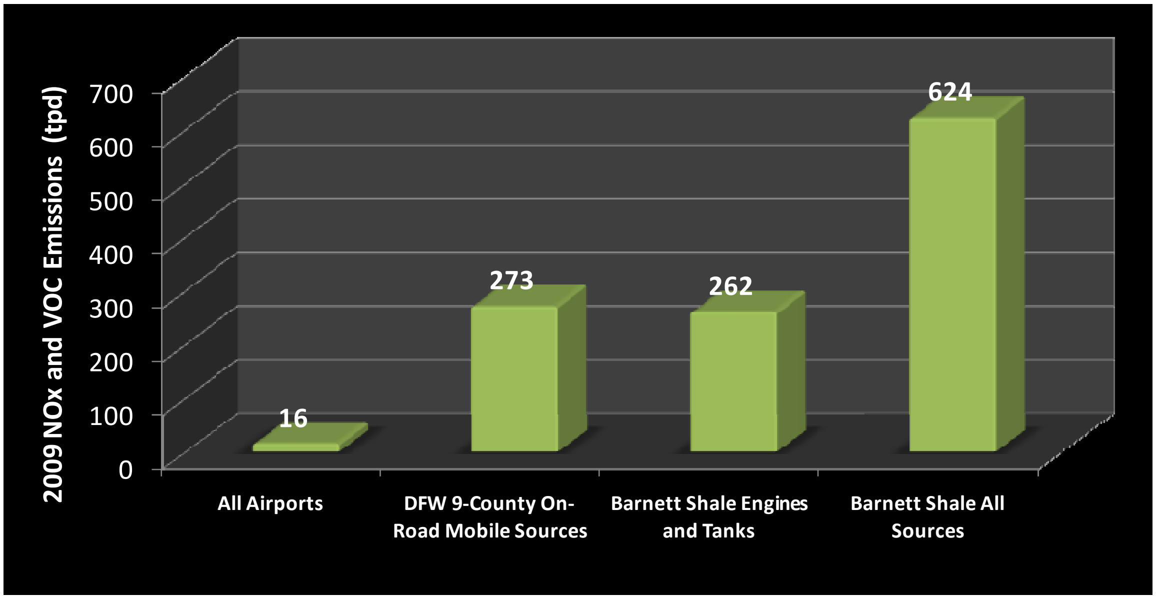
4.4 Comparison of Barnett Shale Emissions to Emissions From Other Sources

Barnett Shale oil and gas production activities are significant sources of air emissions in the north-central Texas area. To help put the levels of Barnett Shale emissions into context, recent emissions inventories for the area were reviewed, and emission rates of ozone and particulate matter precursor emissions were examined.

The Dallas-Fort Worth area is home to two large airports, Dallas Love Field and Dallas-Fort Worth International Airport, plus a number of smaller airports. A recent emissions inventory has estimated 2009 NO_x emissions from all area airports to be approximately 14 tpd, with VOC emissions at approximately 2.6 tpd, resulting in total ozone and particulate matter precursor emissions of approximately 16 tpd. [22-24] For comparison, emissions of VOC + NO_x in 2009 from just the compressor engines in the Barnett Shale area will be approximately 68 tpd, condensate tanks emissions will be approximately 194 tpd, and all sources combined will produce emissions of approximately 624 tpd. In 2009, even after regulatory efforts to reduce NO_x emissions from certain engines, Barnett Shale oil and gas emissions will be many times the emissions from the area's airports.

Recent inventories have also compiled emissions from on-road mobile sources like cars, trucks, motorcycles, etc., in the 9-county DFW nonattainment area [25] By 2009, NO_x + VOC emissions from mobile sources in the 9-county area were estimated to be approximately 273 tpd. Interestingly, NO_x + VOC emissions in 2009 from just the Barnett Shale compressor engines and condensate tanks will be nearly equal to the mobile source emissions from all nine counties in the DFW NAA (262 tpd vs. 273 tpd). Furthermore, NO_x and VOC emissions in 2009 from all Barnett Shale sources (engines and tanks, plus fugitives) will be more than 200% greater than emissions from mobile sources in the entire DFW NAA (624 tpd vs. 273 tpd). Figure 5 summarizes Barnett Shale-related emissions, plus emissions from airports and mobile sources.

Figure 5. Barnett Shale Sources, Airports, & Mobile Sources (2009 Emissions).



5.0 EMISSIONS REDUCTIONS

The previous chapters in this report have estimated the emission rates of ozone and particulate matter precursor compounds, air toxic compounds, and greenhouse gases from different oil and gas sources in the Barnett Shale area. For several of these source categories, off-the-shelf options are available which could significantly reduce emissions, resulting in important air quality benefits. Some of these emissions reductions would also result in increased production of natural gas and condensate, providing an economic payback for efforts to reduce emissions.

5.1 Compressor Engines

Compressors in oil and gas service in the Barnett Shale perform vital roles, to either help get oil and gas out of the shale, to increase pressures of gas at the surface and after separators to the pressures of gathering lines, and to provide the power for the large interstate pipeline systems that move high volumes of gas from production to processing and to customers. At present, most of the work to operate the compressors comes from natural gas-fired internal combustion engines, and these engines can be significant sources of emissions.

New TCEQ rules are scheduled to become effective in early 2009 and they will reduce NO_x, VOC, and other emissions from a subset of the engines in the Barnett Shale – those that are currently in the DFW nonattainment area that had typically not reported into the Texas point source emissions inventory for major sources. These rules are a good first step in addressing emissions from these sources, which had previously gone unnoticed in state emission inventory and regulatory efforts.

However, engines outside the DFW NAA are not subject to the rule. And even within the NAA, the rule will not have the effect of greatly reducing emissions in 2009 compared to 2007 levels, since growth in oil and gas production (and the new engines that are going to be required to power the growth) will begin to overtake the benefits that come from reducing emissions from the pre-2009 fleet (see Table 14).

Two available options for reducing emissions from engines in the Barnett Shale are: (1) extending the TCEQ 2009 engine regulation to all engines in the Barnett Shale, and (2) replacing internal combustion engines with electric motors as the sources of compression power throughout the Barnett Shale area.

i. Extending the 2009 Engine Rule to Counties Outside the DFW Nonattainment Area

Regulations adopted by TCEQ for the DFW NAA and scheduled to take effect in early 2009 will limit NO_x emissions from engines larger than 50 horsepower.[7] Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. Applying these rules to engines outside the nonattainment area would reduce 2009 NO_x emissions from a large number of engines, in particular, rich burn engines between 50 to 500 hp. Emissions of NO_x in 2009 from the entire fleet of engines outside the NAA would drop by approximately 6.5 tpd by extending the 2009 engine rule, an amount greater than mobile source emissions in all of Johnson County (4 tpd), or more than 50% of the emissions from Dallas-Fort Worth International Airport (12.6 tpd).

Extending the 2009 engine rules to counties outside the nonattainment area would likely result in many engine operators installing NSCR systems on rich burn engine exhausts. These systems would not only reduce emissions of NO_x, but they would also reduce emissions of VOC the other ozone and particulate matter precursor. Additional co-benefits of NSCR installations would include reducing concentrations of HAP compounds like benzene and formaldehyde in the communities surrounding natural gas facilities, as well as reducing emissions of the greenhouse gas methane.

Analyses of NSCR installations and operating costs by numerous agencies have indicated that the technology is very cost effective in areas producing ozone or particulate matter precursors. For example, the Illinois Environmental Protection Agency estimated in 2007 that NSCR could control NO_x from 500 hp engines at approximately $330/ton.(26) The U.S. EPA in 2006 estimated that NSCR could control NO_x from 500 hp engines at approximately $92 to 105/ton.(27) A 2005 report examining emissions reductions from compressor engines in northeast Texas estimated NO_x cost effectiveness for NSCR at $112-183/ton and identified VOC reductions as an important co-benefit.(28) These costs are well under the cost effectiveness values of $10,000 to $20,000 per ton often used as upper limits in $PM_{2.5}$, ozone, and regional haze (visibility) regulatory programs. The simultaneous HAPs and methane removal that would occur with NSCR use provide further justification for extending the 2009 engine rule to counties in the Barnett Shale area outside the DFW nonattainment area.

ii. Electric Motors Instead of Combustion Engines for Compressor Power

When considering NO_x, VOC, HAPs, and greenhouse gas emissions from compressor engines, it is important to understand that the work to move the gas in the pipelines is performed by the compressors, which by themselves produce no emissions. The emissions come from the exhaust of the internal combustion engines, which are fueled with a small amount of the available natural gas. These engines provide the mechanical power to run the compressors. The 2007 TCEQ engine survey and the most recent point source emissions inventory indicate that installed compressor engine capacity throughout the Barnett Shale was approximately 1,400,000 hp in 2007, and capacity is likely to increase to over 2,100,000 hp by 2009.

As an alternative to operating the compressors in the Barnett Shale with millions of hp of natural gas burning-engines, the compressors could be operated with electrically-driven motors. The electrification of the wellhead and compressor station engine fleet in the Barnett Shale area has the potential to deliver significant reductions in emissions in North Central Texas. The use of electric motors instead of internal combustion engines to drive natural gas compressors is not new to the natural gas industry, and numerous compressors driven by electric motors are operational throughout Texas. The regulatory environment has not yet required their use in the Barnett Shale.

A few of the many examples of electrically-driven natural gas compressors, positive assessments, and industrial experience with their use in Texas and throughout the U.S., include:

- The Interstate Natural Gas Association of America: "One advantage of electric motors is they need no air emission permit since no hydrocarbons are burned as fuel. However, a highly reliable source of electric power must be available, and near the station, for such units to be considered for an application." (29)
- The Williams natural gas company: "The gas turbine and reciprocating engines typically use natural gas from the pipeline, where the electric motor uses power from an electric transmission line. Selection of this piece of equipment is based on air quality, available power, and the type of compressor selected. Typically electric motors are used when air quality is an issue." (30)

- JARSCO Engineering Corp.: "The gas transmission industry needs to upgrade equipment for more capacity. The new high-speed electric motor technology provides means for upgrading, at a fraction of the life cycle costs of conventional gas powered equipment."[31]
- Pipeline and Gas Journal, June 2007: "Important factors in favor of electric-driven compressor stations that should be considered in the feasibility analysis include the fact that the fuel gas for gas turbine compressor stations will be transformed into capacity increase for the electrically-driven compressor station, and will therefore add revenue to this alternative..." [32]
- Prime mover example: Installations in 2007 at Kinder Morgan stations in Colorado of +10,000 hp electric-driven compressor units. [33]
- Wellhead example: Installations in Texas of wellhead capacity (5 to 400 hp) electrically-driven compressors. [34,35]
- Mechanical Engineering Magazine, December 1996: "Gas pipeline companies historically have used gas-fired internal-combustion engines and gas turbines to drive their compressors. However, this equipment emits nitrogen oxides....According to the Electric Power Research Institute, it is more efficient to send natural gas to a combined-cycle power plant to generate electricity transmitted back to the pipeline compressor station than to burn the natural gas directly in gas-fired compressor engines."[36]
- The Dresser-Rand Corporation: "New DATUM-C electric motor-driven compressor provides quiet, emissions free solution for natural gas pipeline applications – An idea whose time had come." [37]
- Occidental Oil and Gas Corporation: "Converting Gas-Fired Wellhead IC Engines to Electric Motor Drives: Savings $23,400/yr/unit." [38]

The use of an electric motor instead of a gas-fired engine to drive gas compression eliminates combustion emissions from the wellhead or compressor station. Electric motors do require electricity from the grid, and in so far as electricity produced by power plants emits pollutants, the use of electric motors is not completely emissions free. However, electric motor use does have important environmental benefits compared to using gas-fired engines.

Modern gas-fired internal-combustion engines have mechanical efficiencies in the 30-35% range, values that have been relatively static for decades. It is doubtful that dramatic increases in efficiency (for example, to 80 or 90%) are possible anytime in the near future. This means that carbon dioxide emissions from natural gas-fired engines at wellheads and compressor stations are not likely to drop substantially because of efficiency improvements in coming years. In addition, the scrubbing technology that is used in large industrial applications to separate CO2 from other gases also is unlikely to find rapid rollout to the thousands of comparatively-smaller exhaust stacks at natural gas wellheads and compressor stations. The two facts combined suggest that the greenhouse gas impacts from using internal combustion engines to drive compressors are likely to be a fixed function of compression demand, with little opportunity for large future improvements.

In contrast, the generators of grid electric power are under increasing pressure to lower greenhouse gas emissions. Wind energy production is increasing in Texas and other areas. Solar and nuclear power projects are receiving renewed interest from investors and regulators. As the electricity in the grid is produced by sources with lower carbon dioxide emissions, so then the use of electric motors to drive natural gas pipelines becomes more and more climate friendly.

Stated another way, carbon dioxide emissions from gas-fired engines are unlikely to undergo rapid decreases in coming years, whereas the electricity for operating electric motors is at a likely carbon-maximum right now. Electric-powered compression has a long-term potential for decreased climate impact, as non-fossil fuel alternatives for grid electricity generation expand in coming years and decades.

Costs: Estimates were made of the costs were switching from IC engines to electric motors for compression. Costs at sites in the Barnett Shale are highly time and site specific, depending on the cost of electricity and the value of natural gas, the numbers of hours of operation per year, the number and sizes of compressors operated, and other factors.

For this report, sample values were determined for capital, operating and maintenance, and operating costs of 500 hp of either IC engine capacity or electric motor capacity for a gas compressor to operate for 8000 hours per year at a 0.55 load factor. Electric power costs were based on $8/month/kW demand charge, $0.08/kWh electricity cost, and 95% motor mechanical efficiency. Natural gas fuel costs were based on $7.26/MMBtu wellhead natural gas price and a BSFC of 0.0085 MMBtu/hp-hr.

With these inputs, the wellhead value of the natural gas needed to operate a 500 hp compressor with an IC engine for 1 year is approximately $136,000. This is lower than the costs for electricity to run a comparable electric motor, which would be approximately $174,000. In addition to these energy costs, it is important to also consider operating and maintenance (O&M) and capital costs. With an IC engine O&M cost factor of $0.016/hp in 2009 dollars, O&M costs would be approximately $35,000. With an electric motor O&M cost factor of $0.0036/kWh in 2009 dollars, O&M costs would be approximately $6200, providing a savings of nearly $30,000 per year in O&M costs for electrical compression, nearly enough to compensate for the additional energy cost incurred from the additional price premium on electricity in Texas compared to natural gas.

With an IC engine capital cost factor of $750/hp in 2009 dollars, the cost of a 500 hp compressor engine would be approximately $370,000. With an electric motor cost factor of $700/kW, the cost of 500 hp of electrically-powered compression would be approximately $260,000.

The combined energy (electricity or natural gas), O&M, and capital costs for the two options are shown in Table 22, assuming a straight 5-year amortization of capital costs. The data show that there is little cost difference in this example, with a slight cost benefit of around $12,000/year for generating the compression power with an electric motor instead of an IC engine. While this estimate would vary from site to site within the Barnett Shale, there appears to be cost savings, driven mostly by reduced initial capital cost, in favor of electrical compression in the Barnett Shale. In addition to the potential cost savings of electrical compression over engine compression, the lack of a overwhelming economic driver one way or the other allows the environmental benefits of electric motors over combustion engines to be the deciding factor on how to provide compression power in the area.

Table 22. Costs of IC Engine and Electric Motor Compression [example of 500 hp installed capacity].

	IC Engine ($/year)	Electric Motor ($/year)
energy (NG or electricity)	136,000	174,000
O&M	35,000	6,200
capital	74,000	52,000
Total	**245,000**	**232,000**

5.2 Oil and Condensate Tanks

Oil and condensate tanks in the Barnett Shale are significant sources of multiple air pollutants, especially VOC, HAPs, and methane, and the VOC component result in approximately 190 tpy of ozone and PM precursor emissions. Multiple options exist for reducing emissions from oil and condensate tanks, including options that can result in increased production and revenue for well operators.(14) This section will discuss two of these options: flares and vapor recovery units.

i. Enclosed Flares

Enclosed flares are common pollution control and flammable gas destruction devices. Enclosed flares get their name because the flame used to ignite the gases is generated by burner tips installed within the stack well below the top. The flames from enclosed flares are usually not visible from the outside, except during upset conditions, making them less objectionable to the surrounding community compared to open (unenclosed) flares.

Using a flare to control emissions from tanks involves connecting the vents of a tank or tank battery to the bottom of the flare stack. The vapors from oil and condensate tanks are sent to the flare, and air is also added to provide oxygen for combustion. The vapors and air are ignited by natural gas pilot flames, and much of the HAP, VOC, and methane content of the tank vapors can be destroyed. The destruction efficiency for flares can vary greatly depending on residence time, temperature profile, mixing, and other factors. Properly designed and operated flares have been reported to achieve 98% destruction efficiencies.

Applying 98% destruction efficiency to the Barnett Shale oil and condensate tanks emissions estimates shown in Table 16 results in potential emission reductions of 190 tpd of VOC, 15 tpd of HAPs, and 22 tpd of methane. These reductions are substantial and would provide large benefits to the ozone and PM precursor, HAPs, and greenhouse gas emission inventory of the Barnett Shale area. The use of flares, however, also has several drawbacks. One of these is that tank vapor flares need a continuous supply of pilot light natural gas, and reports have estimated pilot light gas consumption at around 20 scfh/flare.(14)

ii. Vapor Recovery Units

Vapor recovery units (VRU) can be highly effective systems for capturing and separating vapors and gases produced by oil and condensate tanks. Gases and vapors from the tanks are directed to the inlet side of a compressor, which increases the pressure of the mixture to the point that many of the moderate and higher molecular weight compounds recondense back into liquid form. The methane and other light gases are directed to the inlet (suction) side of the well site production compressors to join the main flow of natural gas being produced at the well. In this way, VRU use increases the total production of gas at the well, leading to an increase in gas available for metering and revenue production. In addition, liquids produced by the VRU are directed back into the liquid phase in the condensate tank, increasing condensate production and the income potential from this revenue stream. Vapor recovery units are estimated to have control efficiencies of greater than 98%.[14]

iii. The Economics of Capturing Tank Vapors and Gases

The gases and vapors emitted by oil and condensate tanks are significant sources of air pollutants, and the escape of these compounds into the atmosphere also reduces income from hydrocarbon production. With a wellhead value of approximately $7/MMBtu, the 23 tpd of methane that is estimated to be emitted in 2009 from condensate tanks in the Barnett Shale have a value of over $3 million per year. Even more significantly, a price of condensate at $100/bbl makes the 194 tpd of VOC emissions in 2009 from the tanks in the Barnett Shale potentially worth over $67 million per year.

While flaring emissions from oil and condensate tanks in the Barnett Shale would provide substantial environmental benefits, especially in terms of VOC, HAP, and methane emissions capturing these hydrocarbons and directing them into the natural gas and condensate distribution systems would provide both an environmental benefit and a very large potential revenue stream to oil and gas producers. Table 23 presents a summary of the results of an economic analysis performed in 2006 by URS Corporation for using flares or vapor recovery units to control emissions from a single tank battery in Texas.[14] Capital costs were estimated by URS with a 5-year straightline amortization of capital. Flow from the tank battery was 25Mscf/day and VOC emissions were approximately 211 tpy. Costs were in 2006 dollars.

Table 23. Economics of Flares and Vapor Recovery Units.

Control Option	Total Installed Capital Cost ($)	Annual Installed Operating Cost ($/yr)	Operating Cost ($/yr)	Value Recovered ($/yr)	VOC Destruction Cost Effectiveness ($/ton VOC)
Enclosed Flare	40,000	8000	900	NA	40
VRU	60,000	12000	11,400	91,300	($320)*

*VRU produces positive revenue, resulting in zero cost for VOC control, after accounting for value of recovered products.

The URS analysis indicated that flares were able to cost effectively reduce VOC emissions at $40/ton, while VRU units produced no real costs, since operating and installed costs were smaller than the additional revenue generated from the products recovered by VRU operation.

5.3 Well Completions

Procedures have been developed to reduce emissions of natural gas during well completions. These procedures are known by a variety of terms, including "the green flowback process" and "green completions." [39,40] To reduce emissions, the gases and liquids brought to the surface during the final stages of the completion process are collected, filtered, and then placed into production pipelines and tanks, instead of being dumped, vented, or flared. The gas cleanup during a "green" completion is done with special temporary equipment at the well site, and after a period of time (days) the gas and liquids being produced at the well are connected to the permanent separators, tanks, and piping and meters that are installed at the well site.

Emissions during well completions depend on numerous site-specific factors, including the pressure of the fluids brought to the surface, the effectiveness of on-site gas capturing equipment, the control efficiency of any flaring that is done, the chemical composition of the gas and hydrocarbon liquids at the drill site, and the duration of drilling and completion work before the start of regular production.

With all these variables, it is difficult to assess the level of emissions reductions and product recovery that could happen in the Barnett Shale with universal use of "green" completion procedures. Nonetheless, some reports of the effectiveness of green completions are available, including one by the U.S. EPA which estimated 70% capture of formerly released gases with green completions, and another report by Williams Corporation which found that 61% to 98% of gases formerly released during well completions were captured with green completions.[40-41] At least one Barnett Shale producer, Devon Energy, is using green completions on its wells, and they reported $20 million in profits from natural gas and condensate recovered by green completed wells in a 3 year period.[42]

If green completion procedures can capture 61% to 98% of the gases formerly released during well completions, the process would be a more environmentally friendly alternative to flaring of the gases, since flaring destroys a valuable commodity and prevents its beneficial use. Green completions would also certainly be more beneficial than venting of the gases, since this can release very large quantities of methane and VOCs to the atmosphere. Another factor in favor of capturing instead of flaring is that flaring will produce carbon dioxide (a greenhouse gas), carbon monoxide, polycyclic aromatic hydrocarbons, and particulate matter (soot) emissions.

5.4 Fugitive Emissions from Production Wells, Gas Processing, and Transmission

Previous sections of this report addressed opportunities for emission reductions from the point sources in the Barnett Shale area, the compressor engines and oil/condensate tanks, as well as techniques to reduce emissions during well completions. For these, there are off-the-shelf methods to generate emission reductions, and the methods are cost-effective.

Likewise, fugitive emissions from the production wells, gas processing plants, and transmission lines in the Barnett Shale can be minimized with aggressive efforts at leak detection and repair. Unlike controlling emissions from comparatively smaller numbers of engines or tanks (numbering in the hundreds or low thousands per county), fugitive emissions can originate from tens of thousands of valves, flanges, pump seals, and numerous other leak points. While no single valve or flange is likely to emit as much pollution as a condensate tank or compressor station engine, the accumulated mass of all these fugitives can be substantial. This report estimates that emissions of volatile organic compounds and methane from fugitive emissions are approximately equal to emissions from the engines, tanks, and well completions (see Table 21).

There are several measures that producers and processors can take to reduce fugitive emissions.

i. Enhanced Leak Detection and Repair Program

The federal government has established New Source Performance Standards for natural gas processing plants a.k.a. NSPS Subpart KKK.[43] These standards require regularly scheduled leak detection, and if needed, repair activities for items such as pumps, compressors, pressure-relief valves, open-ended lines, vapor recovery systems, and flares. The NSPS applies to plants constructed or modified after January 20, 1984. The procedures and standards in the processing plant NSPS are generally based on the standards developed for the synthetic organic manufacturing chemicals industry.[44]

Fugitive emissions from oil and gas wells, separators, tanks, and metering stations are not covered by the processing plant NSPS. Nonetheless, the leak detection and repair protocols established in the NSPS could certainly be used to identify fugitive emissions from these other items. Leak detection at processing plants covered by the NSPS is performed using handheld organic vapor meters (OVMs). These units could be used at every point along the oil and gas system in the Barnett Shale to identify and reduce emissions of VOCs and methane. Doing so would reduce emissions, and by doing so, increase production and revenue to producers.

It is difficult to estimate the exact degree of emission reductions that are possible with fugitive emission reduction programs. The large and varied number of fugitive emission points (valves, fittings, etc.) at production wells, processing plants, and transmission lines means that each oil and gas related facility in the Barnett Shale will have different options for reducing fugitive emissions. In general, leak detection and repair programs can greatly reduce emissions from faulty units. Nonetheless, even with vigorous implementation of leak detection and repair programs throughout the basin, some level of fugitive emissions is inevitable, given the large size of the oil and gas collection and transmission systems.

ii. Eliminating Natural Gas Actuated Pneumatic Devices

The State of Colorado is currently adopting and implementing VOC control strategies to reduce ambient levels of ozone in the Denver metropolitan area, and to protect the numerous national parks and wilderness areas in the state. As part of this effort, the state investigated the air quality impacts of oil and gas development, including the impacts of the pneumatically-controlled valves and other devices that are found throughout gas production, processing, and transmission systems. The State of Colorado confirmed the basic conclusions arrived at earlier by EPA and GRI in 1995, that these pneumatic devices can be substantial sources of CH_4, VOC, and HAP emissions.[45,46] Much of the following information on these devices and the strategies to control emissions is based on a review of the recent work in Colorado.

Valves and similar devices are used throughout the oil and gas production, processing, and transmission systems to regulate temperature, pressure, flow, and other process parameters. These devices can be operated mechanically, pneumatically, or electrically. Many of the devices used in the natural gas sector are pneumatically operated. Instrument air (i.e. compressed regular air) is used to power pneumatic devices at many gas processing facilities, but most of the pneumatic devices at production wells and along transmission systems are powered by natural gas.[46] Other uses of pneumatic devices are for shutoff valves, for small pumps, and with compressor engine starters.

As part of normal operation, most pneumatic devices release, or “bleed”, gas to the atmosphere. The release can be either continuously or intermittently, depending on the kind of device. In 2003 U.S. EPA estimated that emissions from the pneumatic devices found throughout the production, processing, and transmission systems were collectively one of the largest sources of methane emissions in the natural gas industry.

Some U.S. natural gas producers have reduced natural gas emissions significantly by replacing or retrofitting "high-bleed" pneumatic devices. High-bleed pneumatic devices emit at least 6 standard cubic feet gas per hour.[46] Actual field experience is demonstrating that up to 80 percent of all high-bleed devices in natural gas systems can be replaced or retrofitted with low-bleed equipment.

The replacement of high-bleed pneumatic devices with low-bleed or no-bleed devices can reduce natural gas emissions to atmosphere by approximately 88 or 98 percent, respectively.[21, 47] Anadarko Petroleum Corporation estimated that VOC emissions from their pneumatic devices will be reduced by 464 tpy once 548 of their pneumatic controllers are retrofitted in Colorado.[46]

It may not be possible, however, to replace all high-bleed devices with low or no bleed alternatives. In the state of Colorado, it was estimates that perhaps up to 20 percent of high-bleed devices could not be retrofitted or replaced with low-bleed devices. Some of these included very large devices requiring fast and/or precise responses to process changes which could not yet be achieved with low-bleed devices.

But even for these devices that appear to require high-bleed operation, alternatives are available. Natural gas emissions from both high bleed and low bleed devices can be reduced by routing pneumatic discharge into a fuel gas supply line or into a closed loop controlled system. Another alternative is replacing the natural gas as the pneumatic pressure fluid with pressurized air. Instrument pressurized air systems are sometimes installed at facilities that have a high concentration of pneumatic devices, full-time operator presence, and are on a power grid. In an instrument pressurized air system, atmospheric air is compressed, stored in a volume tank, filtered, and dried. The advantage of a pressurized air system for operating pneumatic devices is that operation is the same whether they air or natural gas is used. Existing pneumatic gas supply piping, control instruments, and valve actuators can be reused when converting from natural gas to compressed air. Almost 100 percent of natural gas emissions would be eliminated if discharge from pneumatic devices is routed into a fuel gas supply line or a closed loop controlled system instead of being vented to atmosphere.

The U.S. EPA runs a voluntary program, EPA Natural Gas STAR, of companies adopting strategies to reduce their emissions. Experience from companies participating in the program indicates that strategies to reduce emissions from pneumatic devices are highly cost effective, and many even pay for themselves in a matter of months.[46] EPA reports that one company replaced 70 high-bleed pneumatic devices with low-bleed devices and retrofitted 330 high-bleed devices, which resulted in an emission reduction of 1,405 thousand cubic meters per year. At $105/m^3, this resulted in a savings of $148,800 per year. The cost, including materials and labor for the retrofit and replacement, was $118,500, and therefore, the payback period was less than one year. Early replacement (replacing prior to projected end-of-service-life) of a high-bleed valve with a low-bleed valve is estimated to cost $1,350. Based on $3/m^3 gas, the payback was estimated to take 21 months. For new installations or end of service life replacement, the incremental cost difference of high-bleed devices versus low-bleed devices was $150 to $250. Based on $3 per Mcf gas, the payback was estimated to take 5 to 12 months.[46]

Overall, there are several cost-effective strategies for reducing emissions from pneumatic devices from Barnett Shale operations and enhance gas collection. These strategies include:

- Installing low- or no-bleed pneumatic devices at all new facilities and along all new transmission lines;
- Retrofitting or replacing existing high-bleed pneumatic devices with low- or no-bleed pneumatic devices;
- Ensuring that all natural gas actuated devices discharge into sales lines or closed loops, instead of venting to the atmosphere;
- Using pressurized instrument air as the pneumatic fluid instead of natural gas.

6.0 CONCLUSIONS

Oil and gas production in the Barnett Shale region of Texas has increased rapidly over the last 10 years and in 2008 production shows no sign of slowing. The great financial benefits and natural resource production that comes from the Barnett Shale brings with it a responsibility to minimize local, regional, and global air quality impacts. This report examined emissions of smog forming compounds, air toxic compounds, and greenhouse gases from point sources in the Barnett Shale, compressor engines and oil/condensate tanks, as well as fugitive and intermittent emissions from production fugitives, well drilling and well completions, gas processing, and transmission fugitives.

By 2009, emissions of smog forming compounds (NOx and VOC) from the engine and tank point sources will be approximately 260 tons per day. The combined emissions from the engines, tanks, and the fugitive and intermittent sources will be approximately 624 tons per day, greater than the estimated emissions of many other source categories in North Central Texas, including the major airports or on-road motor vehicles.

Emissions in 2009 of air toxic compounds from Barnett Shale activities will be approximately 33 tons per day and emissions of greenhouse gases like carbon dioxide and methane will be approximately 30,000 equivalent tons per day.

Cost effective control strategies were identified with the potential to significantly reduce emissions from many of the sources in the Barnett Shale. Among these was the replacement of internal combustion engines with electric motors for compression power, which could eventually reduce smog forming emissions by 50 tpd. Significant emission reductions could also be achieved with the use of vapor recovery units on oil and condensate tanks, which could eliminate 190 tpd of VOC emissions. Efforts to control condensate tank emissions would easily pay for themselves in a matter of months and start generating revenue to producers because of the high value of the gas and condensate that would be captured instead of released to the atmosphere. Fugitive emissions of methane, VOC, and HAPs could be reduced with a program to replace natural gas actuated pneumatic valves and devices with units actuated with compressed air. For those devices in locations where compressed air is impractical to implement, connection of the bleed vents of the devices to sales lines would greatly reduce emissions.

There are significant opportunities available to improve local and regional air quality and reduce greenhouse gas emissions by applying readily available technology and practices to oil and gas production activities in the Barnett Shale.

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