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

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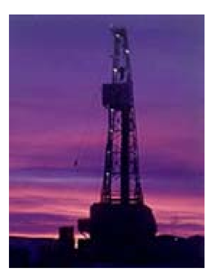


1.0 EXECUTIVE SUMMARY

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, including lower emissions of sulfur, metal compounds, and carbon dioxide. Nevertheless, oil and gas production from the Barnett Shale area can impact local air quality and release greenhouse gases into the atmosphere. The objectives of this study were to develop an emissions inventory of air pollutants from oil and gas production in the Barnett Shale area, and to identify cost-effective emissions control options.

Emission sources from the oil and gas sector in the Barnett Shale area were divided into point sources, which included compressor engine exhausts and oil/condensate tanks, as well as fugitive and intermittent sources, which included production equipment fugitives, well drilling and fracing engines, well completions, gas processing, and transmission fugitives. The air pollutants considered in this inventory were smog-forming compounds (NO_x and VOC), greenhouse gases, and air toxic chemicals.

For 2009, emissions of smog-forming compounds from compressor engine exhausts and tanks were predicted to be approximately 96 tons per day (tpd) on an annual average, with peak summer emissions of 212 tpd. Emissions during the summer increase because of the effects of temperature on volatile organic compound emissions from storage tanks. Emissions of smog-forming compounds in 2009 from all oil and gas sources were estimated to be approximately 191 tpd on an annual average, with peak summer emissions of 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 165 tpd during the summer.

For comparison, 2009 emission inventories recently used by state and federal regulators estimated smog-forming emissions from all airports in the Dallas-Fort Worth metropolitan area to be 16 tpd. In addition, these same inventories had emission estimates for on-road motor vehicles (cars, trucks, etc.) in the 9-county Dallas-Fort Worth metropolitan area of 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties.

The emission rate of air toxic compounds (like benzene and formaldehyde) from Barnett Shale activities was predicted to be approximately 6 tpd on an annual average, and 17 tpd during peak summer days. The largest contributors to air toxic emissions were the condensate tanks, followed by the engine exhausts.

In addition, predicted 2009 emissions of greenhouse gases like carbon dioxide and methane were approximately 33,000 tons per day of CO_2 equivalent. This is roughly equivalent to the expected greenhouse gas impact from two 750 MW coal-fired power plants. The largest contributors to the Barnett Shale greenhouse gas impact were CO_2 emissions from compressor engine exhausts and fugitive CH_4 emissions from all source types.

Cost effective control strategies are readily available that can substantially reduce emissions, and in some cases, reduce costs for oil and gas operators. These options include:

- use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in electric motors as an alternative to internal-combustion engines to drive compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

2.0 BACKGROUND

2.1 Barnett Shale Natural Gas Production

The Barnett Shale is a geological formation that the Texas Railroad Commission (RRC) estimates to extend 5000 square miles in parts of at least 21 Texas counties. The hydrocarbon 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]

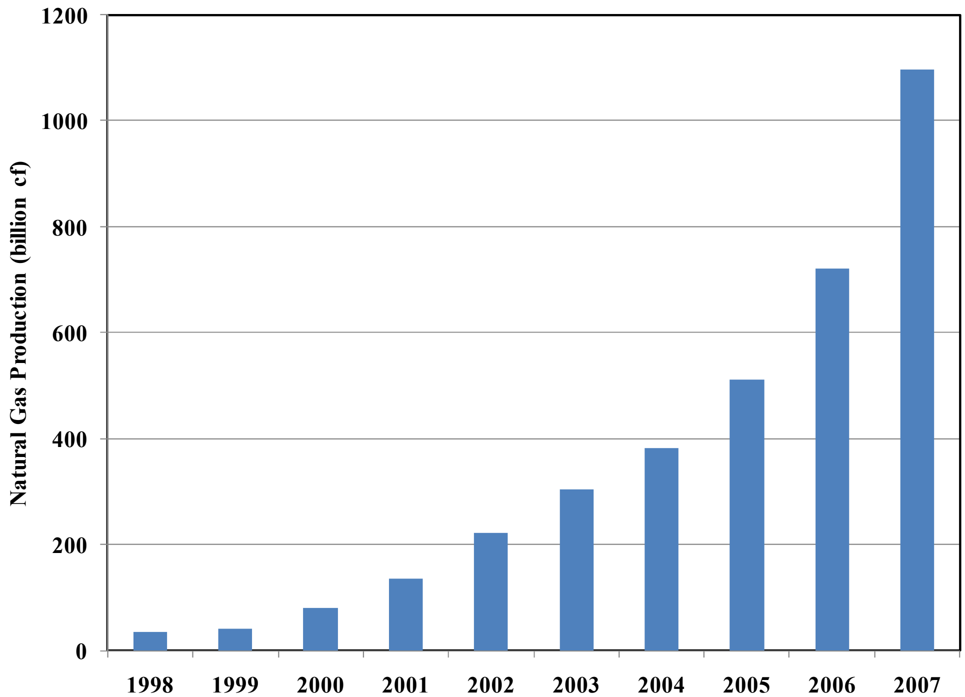


Figure 1. Barnett Shale Natural Gas Production, 1998-2007.

In addition to the recent development of the Barnett Shale, oil and gas production from other geologic formations and conventional sources in north central Texas existed before 1998 and continues to the present time. Production from the Barnett Shale is currently the dominant source of hydrocarbon production in the area from oil and gas activities in the area. Emission sources for all oil and gas activities are considered together in this report.

The issuance of new Barnett Shale area 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 in the area, 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 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 near the city of Fort Worth: Tarrant, Denton, Wise, Parker, Hood, and Johnson Counties. Figure 2 shows a RRC map 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.

Nine (9) counties surrounding the cities of Fort Worth and Dallas have been designated by the U.S. EPA as the D-FW ozone nonattainment area (Tarrant, Denton, Parker, Johnson, Ellis, Collin, Dallas, Rockwall, and Kaufman). Four of these counties (Tarrant, Denton, Parker, and Johnson) have substantial oil or gas production. In this report, these 9 counties are referred to as the D-FW metropolitan area. The areas outside these 9-counties with significant Barnett Shale oil or gas production are generally more rural counties to the south, west, and northwest of the city of Fort Worth. The counties inside and outside the D-FW metropolitan area with oil and gas production are listed in Table 1-3.

Table 1-1. Barnett Shale Area Drilling Permits Issued, 2004-2008.[1]

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

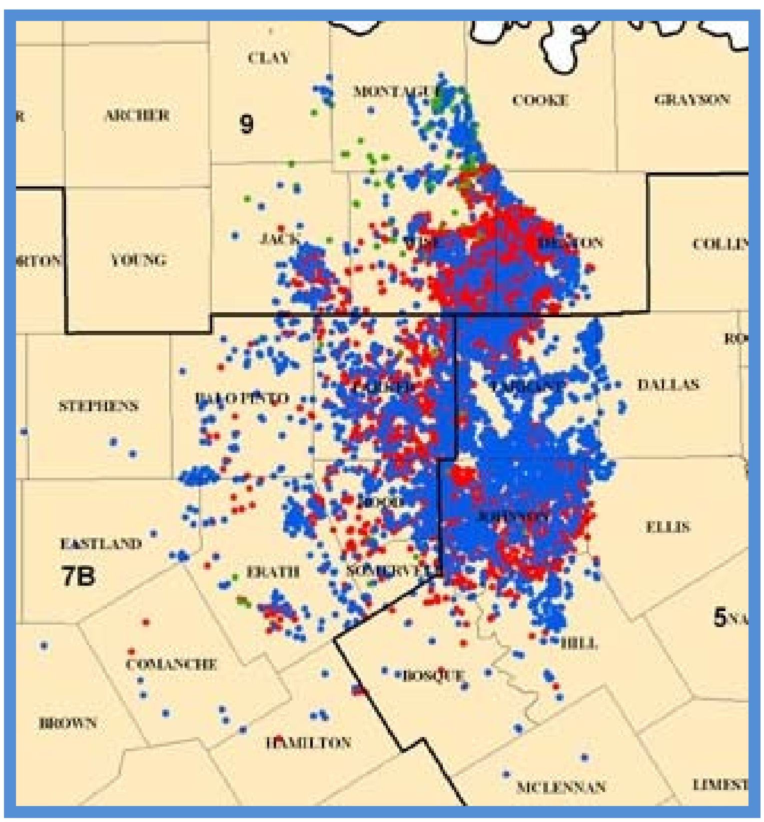
Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.[1]

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

Table 1-3. Relationship Between the D-FW Metropolitan Area and Counties Producing Oil/Gas in the Barnett Shale Area

D-FW 9-County Metropolitan Area	D-FW Metro. Counties Producing Barnett Area Oil/Gas	Rural Counties Producing Barnett Area Oil/Gas
Tarrant	Tarrant	Wise
Denton	Denton	Hood
Parker	Parker	Jack
Johnson	Johnson	Palo Pinto
Ellis	Ellis	Stephens
Collin		Hill
Dallas		Eastland
Rockwall		Somervell
Kaufman		Comanche
		Cooke
		Montague
		Clay
		Hamilton
		Bosque

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



2.2 Air Pollutants and Air Quality Regulatory Efforts

Oil and gas activities in the Barnett Shale area have the potential to emit a variety of air pollutants, including greenhouse gases, ozone and fine particle smog-forming compounds, and air toxic chemicals. The state of Texas has the highest greenhouse gas (GHG) emissions in the U.S., and future federal efforts to reduce national GHG emissions are likely to require emissions reductions from sources in the state. The three anthropogenic greenhouse gases of greatest concern, carbon dioxide, methane, and nitrous oxide, are emitted from oil and gas sources in the Barnett Shale area.

At present, air quality monitors in the Dallas-Fort Worth area show the area to be in compliance with the 1997 fine particulate matter ($PM_{2.5}$) air quality standard, which is 15 micrograms per cubic meter ($\mu g/m^3$) on an annual average basis. In 2006, the Clean Air Scientific Advisory Committee for EPA recommended tightening the standard to as low as 13 $\mu g/m^3$ to protect public health, but the EPA administrator kept the standard at the 1997 level. Fine particle air quality monitors in the Dallas-Fort Worth area have been above the 13 $\mu g/m^3$ level several times during the 2000-2007 time period, and tightening of the fine particle standard by future EPA administrators will focus regulatory attention at sources that emit fine particles or fine particle-forming compounds like NO_x and VOC gases.

2.3 Primary Emission Sources Involved in 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. The primary emission sources in the Barnett Shale oil and gas sector include compressor engine exhausts, oil and condensate tank vents, production well fugitives, well drilling and hydraulic fracturing, well completions, natural gas processing, and transmission fugitives. Figure 3 shows a diagram of the major machinery and process units in the natural gas system.(3)

2.3.1 – Point Sources

i. Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines, and 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 mixture of natural gas, other gases, water, and hydrocarbon liquids. Some gas wells produce little or no condensate, while others produce large quantities. The 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 any entrained 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.

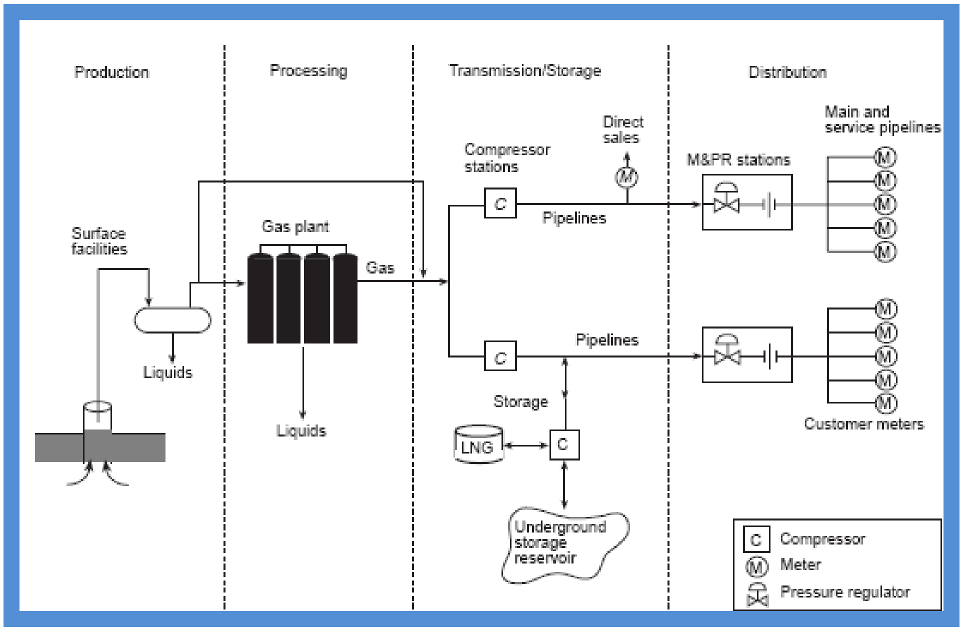


Figure 3. Major Units in The Natural Gas Industry From Wells to Customers. (3)

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.

2.3.2 – 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, compressors, 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, Hydraulic Fracturing, and Completions

Oil and gas drilling rigs require substantial power to from wellbores by driving drill bits to the depths of hydrocarbon deposits. In the Barnett Shale, this power is typically provided by transportable diesel engines, and operation of these engines generates exhaust from the burning of diesel fuel. After the wellbore is formed, additional power is needed to operate the pumps that move large quantities of water, sand/glass, or chemicals into the wellbore at high pressure to hydraulically fracture the shale to increase its surface area and release natural gas.

After the wellbore is formed and the shale fractured, an initial mixture of gas, hydrocarbon liquids, water, sand, or other materials comes to the surface. The standard hardware typically used at a gas well, including the piping, separator, and tanks, are not designed to handle this initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this "well completion" process, and direct the sand, water, and other liquids into ponds or tanks. After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting hardware at the well site. During well completions, the venting/flaring of the gas coming to the surface results in a loss of potential revenue and also in substantial methane and VOC emissions to the atmosphere.

iii. Natural Gas Processing

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. In addition to water, the glycol absorbent 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, and emissions also originate from the numerous flanges, valves, and other fittings.

iv. Natural Gas Transmission Fugitives

Natural gas is transported from wells in mostly underground gathering lines that form networks that can eventually collect gas from hundreds or thousands of well locations. Gas is transported in pipeline networks from wells to processing plants, compressor stations, 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, as well as from compressor intake and outlet seals, compressor rod packing, blow and purge operations, pipeline pigging, 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 for producers.

2.4 Objectives

Barnett Shale area oil and gas production can emit pollutants to the atmosphere which contribute to ozone and fine particulate matter smog, are known toxic chemicals, or contribute to climate change. The objectives of this study were to examine Barnett Shale oil and gas activities and : (1) estimate emissions 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) identify new approaches that can be taken to reduce emissions from Barnett Shale activities; and (4) estimate the emissions reductions and cost effectiveness of implementation of new emission reduction methods.

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 toxics 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-based chemicals that exist in the gas phase or can evaporate from liquids. VOCs can react in the atmosphere to form ozone and fine particulate matter. Methane and ethane are specifically excluded from the definition of VOC because they react slower than the other VOC compounds to produce ozone and fine particles, but they are ozone-causing compounds nonetheless. The HAPs analyzed in this report are a subset of the VOC compounds, and include those compounds that are known or believed to cause human health effects at low doses. 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 CO_2, CH_4, and N_2O were determined individually, and then combined as carbon dioxide equivalent tons (CO_2e). In the combination, CH_4 tons were scaled by 21 and N_2O tons by 310 to account for the higher greenhouse gas potentials of these gases.(4)

Emissions in 2009 were estimated by examining recent trends in Barnett Shale hydrocarbon production, and where appropriate, extrapolating production out to 2009.

State regulatory programs are different for compressor engines inside the D-FW 9-county metropolitan area compared to outside. Engine emissions were determined separately for the two groups.

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) The large amount of production from wells producing from the Barnett Shale, as well as the smaller amounts of production from conventional formations in the area were taken together. The area was analyzed in whole, as well as by counties inside and outside the D-FW 9-county metropolitan area. Production rates in 2009 were predicted by plotting production rates from 2000-2007 and fitting a 2nd-order polynomial to the production rates via the least-squares method and extrapolating out to 2009.

3.3 Compressor Engine Exhausts - Emission Factors and Emission Estimates

Emissions from the natural-gas fired compressor engines in the Barnett Shale were calculated for two types of engines: the generally large engines that had previously reported emissions into the TCEQ's Point Source Emissions Inventory (PSEI) prior to 2007 (a.k.a. PSEI Engines), and the generally smaller engines that had not previously reported emissions (a.k.a. non-PSEI Engines). Both these engine types are located in the D-FW 9-county metropolitan area (a.k.a. D-FW Metro Area), as well as in the rural counties outside the metropolitan area (a.k.a. Outside D-FW Metro Area). The four categories of engines are summarized in Figure 4 and the methods used to estimate emissions from the engines are described in the following sections.

Figure 4. Engine Categories.

Non-PSEI Engines in D-FW Metro Area	PSEI Engines in D-FW Metro Area	PSEI Engines Outside D-FW Metro Area	Non-PSEI Engines Outside D-FW Metro Area

i. Non-PSEI Engines in D-FW Metropolitan 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 other stationary 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 D-FW metropolitan area as part 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. Data summarized by TCEQ from the survey was used for this report to estimate emissions from natural gas 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 metropolitan area, grouped by rich vs. lean burn engines, and also grouped by engines smaller than 50 hp, between 50 - 500 hp, and larger than 500 hp.

Regulations adopted by TCEQ and scheduled to take effect in early 2009 will limit NO_x emissions in the D-FW metropolitan 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 metropolitan 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 HAP compounds that are created by incomplete fuel combustion. 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 the greenhouse gas N_2O were from an 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 emission factors.(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 D-FW 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	1.45	0.27	4.8	424	0.012
lean[h]	>500	0.5	1.45	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: 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).

h: 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).

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 7); 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). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.

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,

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

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 of 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 D-FW 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. PSEI Engines in D-FW Metropolitan Area

In addition to the engines identified in the 2007 TCEQ survey of the D-FW 9-county metropolitan area, many other stationary engines are also in use in the area. These include engines that had already been reporting annual emissions to TCEQ in the PSEI, which are principally large engines at compressor stations.[(12)]

Emissions of NO_x from large engines in the D-FW metropolitan area that were reporting to the TCEQ PSEI were obtained from the 2006 Annual 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 and compression needs 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 for the D-FW metropolitan area.[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 capacities for each county in the Barnett Shale area.[8] Engine capacities were 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 the D-FW metropolitan area. Table 5 summarizes the estimates of installed engine capacity for each engine category.

Table 4. VOC, HAP, GHG Emission Factors for PSEI Engines in D-FW Metropolitan Area

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	1.47	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). Large lean engine VOC emission factor adjusted from 1.6 to 1.47 to account for the effects of NSPS JJJJ rules on VOC emissions.

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 Inside D-FW Metropolitan Area

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).

iii. PSEI Engines Outside D-FW Metropolitan Area

Emissions of NO_x from large engines outside the D-FW metropolitan 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 metropolitan area, the engines outside the metropolitan area are not subject to the new D-FW engine rules scheduled to take effect in 2009.

In addition to the D-FW engine rules, in 2007 the TCEQ passed the East Texas Combustion Rule that limited NO_x emissions from rich-burn natural gas engines larger than 240 hp in certain east Texas counties. Lean burn engines and engines smaller than 240 hp were exempted. The initial proposed rule would have applied to some counties in the Barnett Shale production area, including Cooke, Wise, Hood, Somervell, Bosque, and Hill, but in the final version of the rule these counties were removed from applicability, with the exception of Hill, which is still covered by the rule. Since gas production from Hill County is less than 3.5% of all the Barnett Shale area gas produced outside the D-FW metropolitan area, the East Texas Combustion Rule has limited impact to emissions from Barnett Shale area activity.

Emissions of VOC, HAPs, and greenhouse gases for large engines outside the D-FW metropolitan area were not obtained from the 2006 PSEI. A process similar to the one used to estimate emissions from large engines inside the metropolitan area 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 D-FW metropolitan area. The engine capacities used to estimate emissions are shown in Table 7.

Table 6. VOC, HAP, GHG Emission Factors for PSEI Engines Outside D-FW Metropolitan Area

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	1.45	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). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
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 D-FW Metropolitan Area

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).

iv. Non-PSEI Engines Outside the D-FW Metropolitan Area

The Point Source Emissions Inventory (PSEI) only contains emissions from a fraction of the stationary engines in the Barnett Shale area, principally the larger compressor engines with emissions above the PSEI reporting thresholds. The 2007 TCEQ engine survey of engines inside the D-FW metropolitan area demonstrated that the PSEI does not include a substantial fraction of total engine emissions. Most of the missing engines in the metropolitan area were units with emissions individually below the TCEQ reporting thresholds, but the combined emissions from large numbers of smaller engines can be substantial. The results of the 2007 survey indicated that there were approximately 680,000 hp of installed engine capacity in the D-FW metropolitan area not previously reporting to the PSEI.[6]

Natural gas and casinghead gas production from metropolitan counties in 2007 was approximately 1,000 Bcf . A "non-PSEI" compressor engine capacity production factor of 226 hp/(MMcf/day) was determined for the Barnett Shale area. This capacity factor accounts for all the small previously hidden engines that the 2007 survey showed come into use in oil and gas production activities in the area. This production factor was used along with 2007 gas production rates for the counties outside the D-FW metropolitan area to estimate non-PSEI engine emissions from these counties. The new production factor accounts for the fact that counties outside the metro area 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 metro area. Without a detailed engine survey in the rural counties of the same scope as the 2007 survey performed within the D-FW metropolitan counties, use of the non-PSEI production factor provides a way to estimate emissions from engines not yet in state or federal inventories. The capacity of non-PSEI reporting engines in the rural counties of the Barnett Shale was determined 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 D-FW Metropolitan Area

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	10.3	0.43	0.088	0.89	424	0.0077
rich	>500	0.89	0.11	0.022	0.22	424	0.026
lean	<500	5.2	1.45	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). Rich burn engines 50-500 hp NOx emission factor adjusted from 13.6 to 10.3 to account for the effects of NSPS JJJJ rules on NOx emissions and the effect of the TCEQ East Texas Combustion Rule on Hill County production. Rich burn engines >500 adjusted from 0.9 to 0.89 to account for the effect of the TCEQ East Texas Combustion Rule on Hill County production. Lean burn <500 hp engine post-2007 emission factor adjusted from 6.2 to 5.15 to account for the effects of NSPS JJJJ rules on NOx emissions.
gg: email from TCEQ to SMU, August 6, 2008; rich (>500) based on 75% control (reference 8). Small lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
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 Metropolitan Area by Engine Type/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 in this study to calculate Barnett Shale-specific emission factors for VOC, CH_4, HAPs, and CO_2, instead of using a more general Texas-wide emission factor. The URS study was conducted during daylight hours in July 2006, when temperatures in North Texas are significantly above the annual average. Therefore, the results of the URS investigation were used to calculate "Peak Summer" emissions. The HAPs identified in the URS study included n-hexane, benzene, trimethylpentane, toluene, ethylbenzene, and xylene. The emission factors used to calculate peak summer emissions from Barnett

Shale condensate and oil tanks are shown in Table 10-1. Figure 5 shows a condensate tank battery from the 2006 URS study report.

Figure 5. Example Storage Tank Battery (left), Separators (right), and Piping.[14]

Computer modeling data were provided during personal communications with a Barnett Shale gas producer who estimated VOC, CH_4, HAPs, and CO_2 emissions from a number of their condensate tanks.[15] The tanks were modeled with ambient temperatures of 60 F, which the producer used to represent annual hourly mean temperatures in the D-FW area. These modeling results were used in this report to predict annual average condensate tank emission factors for the Barnett Shale area. The annual average emission factors are shown in Table 10-2.

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

Table 10-1. Peak Summer Emission Factors.[14]

	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

Table 10-2. Annual Average Emission Factors.[15]

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	10	0.20	1.7	0.23
oil	1.3	0.013	0.26	0.70

Emissions for 2007 were calculated for each county in the Barnett Shale area, using 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,

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

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, P_c was the production rate of condensate or oil, and C was a factor to account for the reduction in emissions due to vapor-emissions controls on some tanks. For this report, the use of vapor-emissions controls on some tanks was estimated to provide a 25% reduction in overall area-wide emissions.

3.3 Production Fugitives - 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 flanges, valves, pneumatic devices, or other 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 network 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. Volume emissions were converted to mass emissions with a density of 0.0483 lb/scf. Multiple Barnett Shale gas producers provided gas composition, heat content data, and area-wide maps of gas composition. The area-wide maps of gas composition were used to estimate gas composition for each producing county. These county-level data were weighted by the fraction of total area production that originated from each county to calculate area-wide emission factors. 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)
11	0.26	99	1.9

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. The area-wide unprocessed natural gas composition based on data from gas producers was 74% CH_4, 8.2% VOC, 1.4% CO_2, and 0.20% HAPs, on a mass % basis. HAPs in unprocessed natural gas can include low levels of n-hexane, benzene, or other compounds.

3.4 Well Drilling, Hydraulic Fracturing Pump Engines, and Well Completions - Emission Factors and Emission Estimates

Emissions from the diesel engines used to operate well drilling rigs and from the diesel engines that power the hydraulic fracturing pumps were estimated based on discussions with gas producers and other published data. Well drilling engine emissions were based on 25 days of engine operation for a typical well, with 1000 hp of engine capacity, a load factor of 50%, and operation for 12 hours per day. Hydraulic fracturing engine emissions were based on 4.5 days of operation for a typical well, with 1000 hp of capacity, a load factor of 50%, and operation for 12 hours per day. Some well sites in the D-FW are being drilled with electric-powered rigs, with electricity provided off the electrical grid. Engines emission estimates in this report were reduced by 25% to account for the number of wells being drilled without diesel-engine power.

In addition to emissions from drilling and fracing 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.

Discussions with Barnett Shale gas producers that are currently employing “green completion” methods to capture natural gas and reduce emissions during well completions suggests that typical well completions in the Barnett Shale area can release approximately 5000 Mcf of natural gas/well. This value, which is very close to the median value obtained from previous studies (References 18-21), was used to estimate well completion emissions in this report.

The number of completed gas wells reporting to the RRC was 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. 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 new well completions/year for each year. Emission estimates were prepared for the entire Barnett Shale area, as well as inside and outside the D-FW metropolitan area. The data from 2004-2008 show that 71 percent of new wells are being installed in the D-FW metropolitan area, 29 percent of new wells are outside the metropolitan area, and the rate of new completions has been steady since 2004. Emissions of VOC, HAPs, CH_4, and CO_2 were estimated using the same natural gas composition used for production fugitive emissions.

Some gas producers are using green completion techniques to reduce emissions, while others destroy natural gas produced during well completions by flaring. To account for the use of green completions and control by flaring, natural gas emission estimates during well completions were reduced by 25% in this report.

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, 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 exhaust emissions that 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 the portion of gas production that is processed, estimated as 519 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with an area-wide natural gas composition, excluding the gas from areas of the Barnett Shale that does not require any processing. Volume emissions were converted to mass emissions with a natural gas density of 0.0514 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)
14	0.3	45	1.0

Processing fugitive emissions were calculated with Equation 4,

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

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. The composition of the natural gas produced in the Barnett Shale that is processed was estimated to be 65% CH_4, 1.5% CO_2, 20% VOC, and 0.48% HAPs, on a mass % basis. Not all natural gas from the Barnett Shale area requires processing.

3.6 Transmission Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from the transmission of natural gas will vary depending on the pressure of pipelines, the integrity of the piping, fittings, and valves, the chemical composition of the gas being transported, the tightness of compressor seals and rod packing, the frequency of blow down events, 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 that were previously addressed in this report, were estimated to be approximately 35% of total fugitive emissions, or 0.49% 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 0.49% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were developed considering that a significant portion of the gas moving through the network does not require processing, while the portion of the gas with higher molecular weight compounds will go through processing. In addition, all gas will have a dry (high methane) composition after processing as it moves to compressor stations and then on to customers. Overall area-wide transmission fugitive emissions were calculated with a gas composition of 76% CH_4, 5.1% VOC, 1.4% CO_2, and 0.12% HAPs, by mass %. 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	0.28	175	3.3

Transmission fugitive emissions were calculated with Equation 5,

$$M_{tr,i} = E_i * P_g / 2000 \qquad (5)$$

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 Sources

i. Compressor Engine Exhausts

Emissions from compressor engines in the Barnett Shale area are summarized in Tables 14 and 15. Results indicate that engines are significant sources of ozone and particulate matter precursors (NO_x and VOC), with 2007 emissions of 66 tpd. Emissions of NO_x are expected to fall 50% from 32 to 16 tpd for engines in the Dallas-Fort Worth metropolitan area because of regulations scheduled to take effect in 2009 and the installation of NSCR units on many engines. Large reductions are unlikely because of the growth in natural gas production. For engines outside the D-FW metropolitan area counties, NO_x emissions will rise from 19 tpd to 30 tpd because of the projected growth in natural gas production and the fact that engines in these counties are not subject to the same regulations as those inside the metropolitan area.

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 for the metropolitan area counties 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 contribution to greenhouse gases was smaller for the engine exhausts than for the other sources reviewed in this report.

Table 14. Emissions from Compressor Engine Exhausts.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Engines	32	13	2.2	35	7261	16	16	2.9	49	11294
Outside Metro Engines	19	2.5	0.45	7.4	1649	30	3.8	0.70	12	2583
Engines Total	**51**	**15**	**2.7**	**43**	**8910**	**46**	**19**	**3.6**	**61**	**13877**

Table 15. Greenhouse Gas Emissions Details.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	CO2	CH4	N2O	CO2e	CO2	CH4	N2O	CO2e
D-FW Metro Engines	6455	35	0.20	7261	10112	49	0.28	11294
Outside Metro Engines	1475	7.4	0.062	1649	2310	12	0.10	2583
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 Tables 16-1 and 16-2. Annual average emissions are shown in Table 16-1, and peak summer emissions are shown in Table 16-2.

On an annual average, emissions of VOCs from the tanks were 19 tpd in 2007, and emissions will increase to 30 tpd in 2009. Because of the effects of temperature on hydrocarbon liquid vapor pressures, peak summer emissions of VOC were 93 tpd in 2007, and summer emissions will increase to 146 tpd in 2009.

Substantial HAP emissions during the summer were determined for the tanks, with 2007 emissions of 7.2 tpd and 2009 emissions of 11 tpd. Greenhouse gas emissions from the tanks are almost entirely from CH_4, with a small contribution from CO_2. Annual average greenhouse gas emissions were 95 tpd in 2007, and will increase to 149 tpd in 2009.

Table 16. Emissions from Condensate and Oil Tanks.

Table 16-1. Annual Average Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	8.9	0.18	2.1	44	14	0.28	3.2	69
Outside Metro Tanks	10	0.21	2.4	51	16	0.32	3.8	80
Tanks Total	**19**	**0.39**	**4.5**	**95**	**30**	**0.60**	**7.0**	**149**

Table 16-2. Peak Summer Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	43	3.3	6.7	142	67	5.2	10	222
Outside Metro Tanks	50	3.8	7.8	166	79	6.0	12	261
Tanks Total	**93**	**7.2**	**15**	**308**	**146**	**11**	**23**	**483**

4.2 Fugitive 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 emissions, with VOC emissions expected to grow from 2007 to 2009 from 17 to 26 tpd. Production fugitives are also very large sources of methane emissions, leading to large CO_2 equivalent greenhouse gas emissions. Greenhouse gas emissions were 3100 tpd in 2007 and will be 4900 tpd in 2009.

Table 17. Emissions from Production Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Production Fugitives	11	0.27	102	2147	18	0.43	160	3363
Outside Metro Production Fugitives	5.2	0.12	46	971	8.1	0.19	72	1521
Production Fugitives Total	**17**	**0.40**	**148**	**3118**	**26**	**0.62**	**232**	**4884**

ii. Well Drilling, Hydraulic Fracturing, and Well Completions

Emissions from well drilling engines, hydraulic fracturing pump engines, and well completions are shown in Table 18. These activities are significant sources of the ozone and fine particulate precursors, as well as very large sources of greenhouse gases, mostly from methane venting during well completions. Greenhouse gas emissions are estimated to be greater than 4000 CO_2 equivalent tons per year. Based on 2000-2007 drilling trends, approximately 71% of the well drilling, fracing, and completion emissions will be coming from counties in the D-FW metropolitan area, with the remaining 29% coming from counties outside the metropolitan area.

Table 18. Emissions from Well Drilling, Hydraulic Fracturing, and Well Completions.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Well Drilling and Well Completion	3.9	15	0.35	130	2883	3.9	15	0.35	130	2883
Outside Metro Well Drilling and Well Completions	1.6	6.1	0.14	53	1178	1.6	6.1	0.14	53	1178
Well Drilling and Completions Emissions Total	**5.5**	**21**	**0.49**	**183**	**4061**	**5.5**	**21**	**0.49**	**183**	**4061**

iii. Natural Gas Processing

Processing of Barnett Shale natural gas results in significant emissions of VOC and greenhouse gases, which are summarized in Table 19. Emissions of VOC were 10 tpd in 2007 and are expected to increase to 15 tpd by 2009. Greenhouse gas emissions, largely resulting from fugitive releases of methane, were approximately 670 tpd in 2007 and will be approximately 1100 tpd in 2009.

Table 19. Emissions from Natural Gas Processing.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Processing Fugitives	6.7	0.16	22	464	10	0.26	35	727
Outside Metro Processing Fugitives	3.0	0.07	10	210	4.7	0.12	16	329
Processing Fugitives Total	**10**	**0.24**	**32**	**674**	**15**	**0.37**	**50**	**1056**

iv. Transmission Fugitives

Transmission of Barnett Shale natural gas results in significant emissions of greenhouse gases and VOC. Greenhouse gas emissions from transmission fugitives are larger than from any other source category except compressor engine exhausts. Emissions of VOC in 2007 from transmission were approximately 18 tpd in 2007 and are estimated to be 28 tpd in 2009. Greenhouse gas emissions from methane fugitives result in emissions of approximately 5500 tpd in 2007 and 8600 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
D-FW Metro Transmission Fugitives	12	0.29	181	3799	19	0.46	283	5952
Outside Metro Transmission Fugitives	5.5	0.13	82	1718	8.6	0.21	128	2691
Transmission Fugitives Total	**18**	**0.43**	**262**	**5517**	**28**	**0.67**	**411**	**8643**

4.3 All Sources Emission Summary

Emissions from all source categories in the Barnett Shale area are summarized in Table 21-1 on an annual average basis, and are summarized in Table 12-2 on a peak summer basis. Annual average emissions for 2009 of ozone and particulate precursors (NO_x and VOC) were approximately 191 tpd, and peak summer emissions of these compounds were 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 133 tpd during the summer (Tarrant, Denton, Parker, Johnson, and Ellis).

Estimates of greenhouse gas emissions from the sector as a whole were quite large, with 2009 emissions of approximately 33,000 tpd. The greenhouse gas contribution from compressor engines was dominated by carbon dioxide, while the greenhouse gas contribution from all other sources was dominated by methane. Emissions of HAPs were significant from Barnett Shale activities, with emissions in 2009 of 6.4 tpd in 2009 on an annual average, and peak summer emissions of 17 tpd.

Table 21. Emissions Summary for All Source Categories.

Table 21-1. Annual Average Emissions from All Sources.

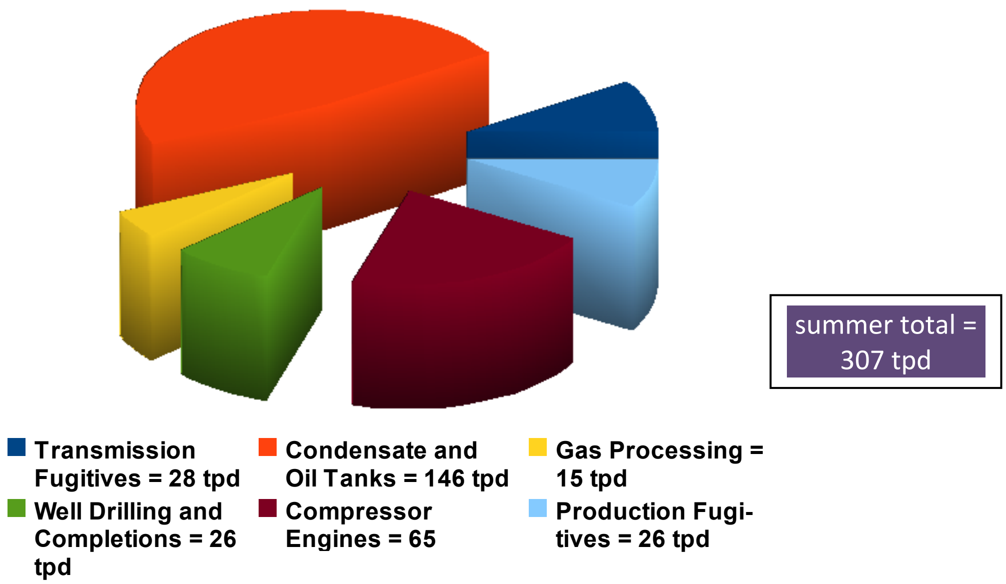
	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	19	0.39	4.5	95	0	30	0.60	7.0	149
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**100**	**4.6**	**673**	**22375**	**51**	**139**	**6.4**	**945**	**32670**

Table 21-2. Peak Summer Emissions from All Sources.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	93	7.2	15	308	0	146	11	23	483
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**174**	**11**	**683**	**22588**	**51**	**255**	**17**	**961**	**33004**

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 and fracing pump engines. All source categories in the Barnett Shale contributed to VOC emissions, but the largest group of VOC sources was condensate tank vents. Figure 6 presents the combined emissions of NO_x and VOC during the summer from all source categories in the Barnett Shale.

Figure 6. Summer Emissions of Ozone & Fine Particulate Matter Precursors (NO_x and VOC) from Barnett Shale Sources in 2009.



4.4 Perspective on the Scale of Barnett Shale Air Emissions

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 government emissions inventories for the area were reviewed, and emission rates of smog 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 summer 2009 from just the compressor engines in the Barnett Shale area will be approximately 65 tpd, and summer condensate tanks emissions will be approximately 146 tpd. In 2009, even after regulatory efforts to reduce NO_x emissions from certain compressor engine types, Barnett Shale oil and gas emissions will be many times the airports' emissions.

Recent state inventories have also compiled emissions from on-road mobile sources like cars, trucks, etc., in the 9-county D-FW metropolitan area.(25) By 2009, NO_x + VOC emissions from mobile sources in the 9-county area were estimated by the TCEQ to be approximately 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd (Denton, Tarrant, Parker, Johnson, and Ellis). As indicated earlier, summer oil and gas emissions in the 5-counties of the D-FW metropolitan area with significant oil and gas production was estimated to be 165 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties (165 vs. 121 tpd).

Emissions of NO_x and VOC in the summer of 2009 from all oil and gas sources in the Barnett Shale 21-county area will exceed emissions from on-road mobile sources in the D-FW metropolitan area by more than 30 tpd (307 vs. 273 tpd).

Figure 7 summarizes summer Barnett Shale-related emissions, plus TCEQ emission estimates from the airports and on-road mobile sources. Figure 8 presents annual average emissions from these sources.

Figure 7. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Summer 2009 Emissions).

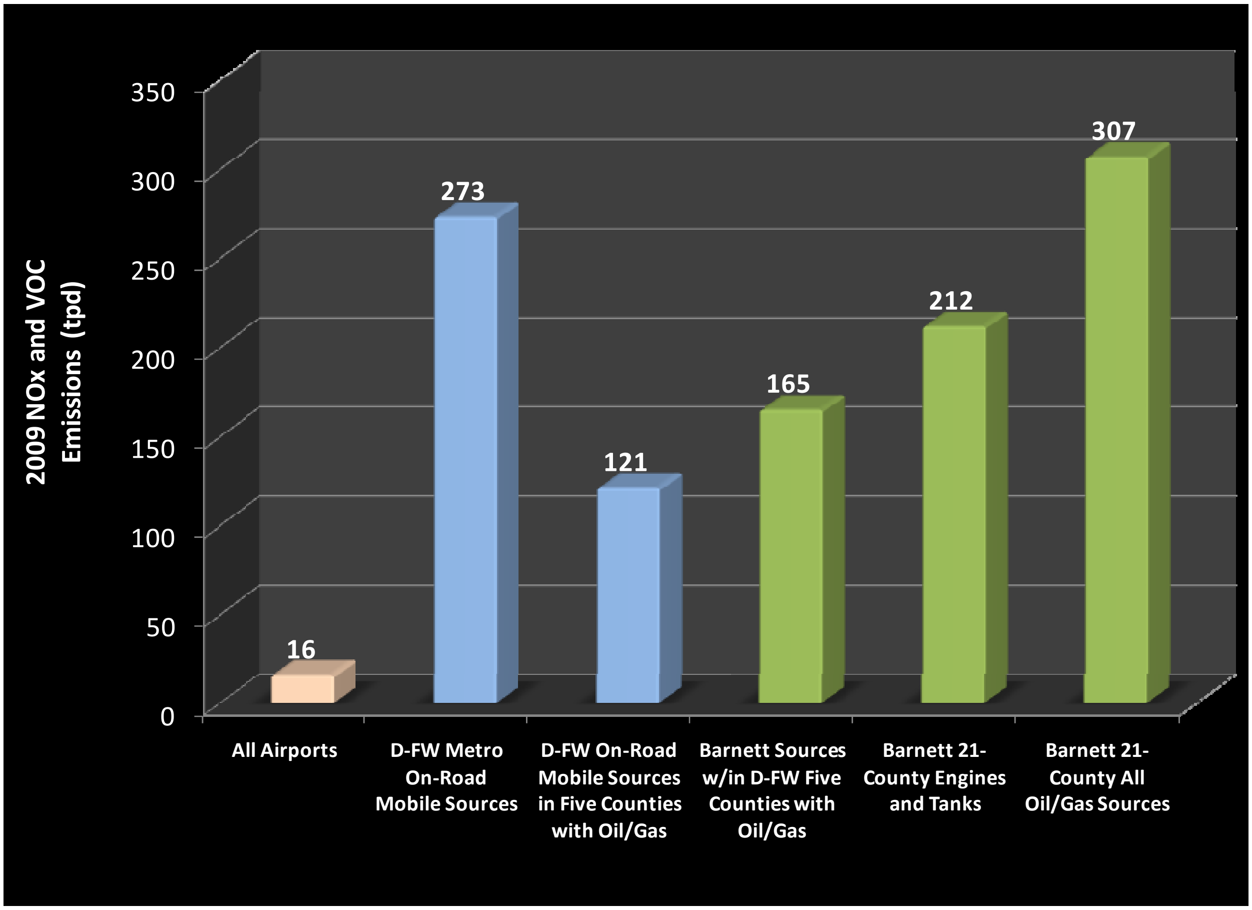
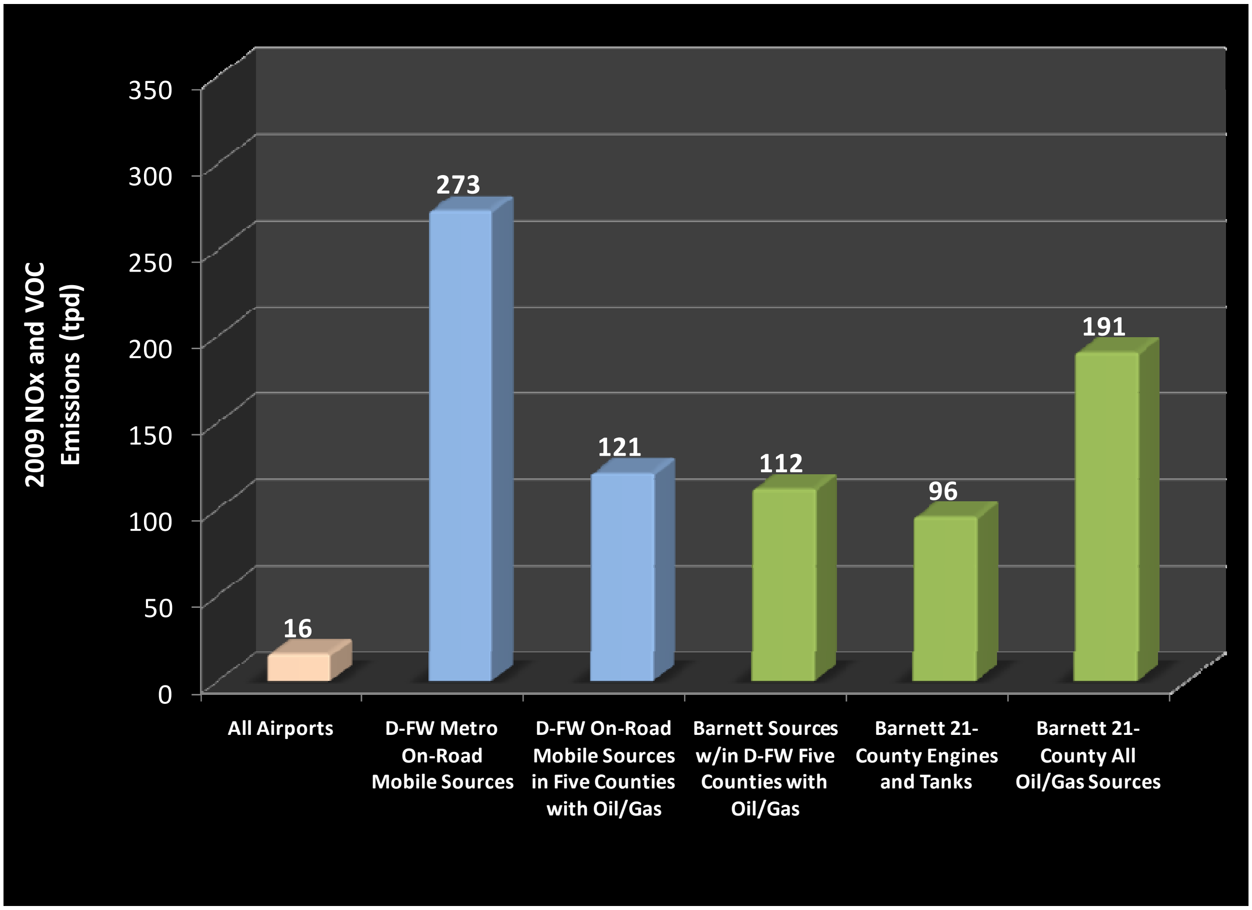


Figure 8. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Annual Average 2009 Emissions).



5.0 EMISSIONS REDUCTION OPPORTUNITIES

The previous sections of 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 Engine Exhausts

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 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 D-FW metropolitan 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 D-FW metropolitan area are not subject to the rule. And even within the metropolitan area, 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 area 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.

i. Extending the 2009 Engine Rule to Counties Outside the D-FW Metropolitan Area

Regulations adopted by TCEQ for the D-FW metropolitan area 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 metropolitan 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 engines outside the metropolitan area would drop by approximately 6.5 tpd by extending the D-FW 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 D-FW engine rule to counties outside the metropolitan 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 be expected to reduce emissions of VOC, the other ozone and particulate matter precursor, by approximately 75% or greater.[26a] Additional co-benefits of NSCR installations would include lower emissions of organic HAP compounds like benzene and formaldehyde, lower emissions of methane, and lower emissions of carbon monoxide. The level of HAP, methane, and carbon monoxide control would also be expected to be 75% or greater with typical NSCR installations.[26a]

Analyses of NSCR installations and operating costs by numerous agencies have indicated that the technology is very cost effective. For example, the Illinois Environmental Protection Agency estimated in 2007 that NSCR could control NO_x from 500 hp engines at approximately $330/ton.[26b] 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 D-FW engine rule to counties outside the metropolitan 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 direct combustion 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. Unfortunately, current regulations have not yet required their use in the Barnett Shale.

A few of the many examples of electrically-driven natural gas compressors, positive technical 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 that 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 addition, the scrubbing technology that is used in some large industrial applications to separate CO_2 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 the future.

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 an 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. 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. 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)

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 7 tpd of methane that is estimated to be emitted in 2009 from condensate tanks in the Barnett Shale have a value of over $800,000 per year. Even more significantly, a price of condensate at $100/bbl makes the 30 tpd of VOC emissions in 2009 from the tanks in the Barnett Shale potentially worth over $10 million per year.

While flaring emissions from tanks in the Barnett Shale would provide substantial environmental benefits, especially in terms of VOC 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.

ii. 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 30 tpd of VOC, 0.6 tpd of HAPs, and 7 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]

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 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 and quickly generated additional revenue from the products recovered by VRU operation. There was a less-than 1 year payback on the use of a VRU system, followed by years of the pollution control device becoming steady revenue source.

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 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 directed to the permanent separators, tanks, and piping and meters that are installed at the well site. Green completion methods are not complex technology and can be very cost effective in the Barnett Shale. The infrastructure is well-established and gathering line placement for the initial collection of gas is not a substantial risk since wells are successfully drilled with a very low failure rate.

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.

Some recent reports of the effectiveness of green completions in the U.S. 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] 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 can 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

Fugitive emissions from the production wells, gas processing plants, gas compressors, 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 engine exhaust stack, the cumulative mass of all these fugitives can be substantial. There are readily-available measures that can 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), and inspections are required to be done on a specified schedule. These same procedures 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 nature 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 help identify faulty units and greatly reduce their emissions.

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 ports 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.

The U.S. EPA runs a voluntary program, EPA Natural Gas STAR, for companies adopting strategies to reduce their methane 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, cost-effective strategies are available for reducing emissions and enhance gas collection from pneumatic devices in Barnett Shale area operations. 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. 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 oil and gas activity in the Barnett Shale area, and identified methods for reducing emissions.

Emissions of ozone and fine particle smog forming compounds (NOx and VOC) will be approximately 191 tons per day on an annual average basis in 2009. During the summer, VOC emissions will increase, raising the NOx + VOC total to 307 tpd, greater than the combined emissions from the major airports and on-road motor vehicles in the D-FW metropolitan area.

Emissions in 2009 of air toxic compounds from Barnett Shale activities will be approximately 6 tpd on an annual average, with peak summer emissions of 17 tpd.

Emissions of greenhouse gases like carbon dioxide and methane will be approximately 33,000 CO_2 equivalent tons per day. This is roughly comparable to the greenhouse gas emissions expected from two 750 MW coal-fired power plants.

Cost effective emission control methods are available with the potential to significantly reduce emissions from many of the sources in the Barnett Shale area, including

- the use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in of electric motors as an alternative to internal-combustion engines to drive gas compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

Large reductions in greenhouse gas emissions could be achieved through the use of green completion methods on all well completions, with the potential to eliminate almost 200 tpd of methane emissions while increasing revenue for producers by recovering saleable gas. In addition, the replacement of internal combustion engines with electric motors for compression power could reduce smog-forming emissions in the D-FW metropolitan area by 65 tpd. Significant emission reductions could also be achieved with the use of vapor recovery units on oil and condensate tanks, which could eliminate large amounts of VOC emissions. Vapor recovery units on condensate tanks would pay for themselves in a matter of months by generating additional revenue to producers from 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 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 also could greatly reduce emissions.

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

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Images on the cover page from the Texas Railroad Commission and the U.S. Department of Energy.

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Finally, the statements and recommendations in this study are those of the author, and do not represent the official positions of Southern Methodist University.