2. 2002 BASE YEAR EMISSION INVENTORY

INTRODUCTION

This section describes the base year 2002 emission inventory of oil and gas area sources for the Western States. The focus of this inventory effort was to estimate emissions of nitrous oxides (NOx) from oil and gas production operations. In the early stages of this project, major NOx sources were identified and methodologies were defined for estimating emissions from those sources. The major NOx sources addressed by this inventory are: drill rigs, gas compressor engines, and coalbed methane pump engines. Emissions from minor NOx and VOC wellhead processes for which emission factors were available were also estimated.

Emissions for oil and gas point sources are also being provided by ENVIRON, but they are not addressed in this document beyond what is necessary to describe measures used to eliminate double counting. Also, the emissions summaries presented in this document currently include emissions that may be classified as falling under tribal jurisdiction. The emissions estimates presented here should be viewed as representing emissions within a geographic area defined by State borders, in which emissions on tribal lands are currently included. ENVIRON is preparing separate emissions estimates of tribal oil and gas emissions for four tribes. Those emissions estimates are being reconciled with the emissions reported here, and a separate documentation of tribal emissions is being prepared.

Though similar procedures are being used to estimate emissions for the tribal inventories, those inventories are not simply a restatement of emission presented here. Thus the reconciliation of the state and tribal inventories will result in emission totals for the WRAP region that are close, but not equal to the totals presented in this document.

Apart from those western States that have no oil or gas production, such as Idaho and Washington, the only State for which area source emissions are not estimated is the State of California. The California Air Resources Board (CARB) has provided area source oil and gas emissions estimates directly to WRAP. Those estimates have been adopted into this inventory and are considered to be complete.

Table 2-1 presents a summary of NOx emissions from oil and gas area sources in the WRAP States. The emissions are distinguished by source category, except in California where only the total NOx emission from the ARB inventory is given. Point source emissions in Table 2-1 are divided into two categories: “Gas/Oil Transmission” and “Other”. Emissions in the “Gas/Oil Transmission” category are those emissions attributed to gas compressor stations, except in Alaska where pump stations on the Trans-Alaska Pipeline make a large contribution. In most states, emissions in the “Other” category are primarily due to gas processing operations, with some contribution from larger storage facilities. However, due to distinctive permitting and inventory methods, in Colorado and Alaska the “Other” category includes nearly all non-transmission oil and gas operations.

Table 2-1. 2002 State total NOx emissions (tons) from oil and gas sources.

State	Area Sources, WRAP Oil and Gas Inventory						Point Sources			TOTAL
	Compressors	Drill Rigs	Wellhead	CBM Generators	Medium-size Facilities	Total	Gas/Oil Transmission	Other	Total	
Alaska		877	9			**886**	268	43,987	**44,255**	**45,142**
Arizona*	7	-	9			**16**	3,669	-	**3,669**	**3,685**
California						**8,070**	4,101	6,594	**10,695**	**18,765**
Colorado		5,736	15,953	1,489		**23,178**	4,019	23,206	**27,225**	**50,403**
Idaho	-	-	-			**-**	2,590	-	**2,590**	**2,590**
Montana	2,027	1,044	4,721			**7,792**	3,785	204	**3,989**	**11,781**
Nevada	0	24	5		33	**62**	120	-	**120**	**182**
New Mexico	40,621	6,653	13,967	234		**61,475**	29,246	27,193	**56,439**	**117,914**
North Dakota	1,401	1,536	176		1,518	**4,631**	559	2,979	**3,538**	**8,169**
Oregon	20	-	12		54	**85**	1,182	-	**1,182**	**1,267**
South Dakota	256	36	47		28	**367**	323	-	**323**	**690**
Utah	1,182	676	2,158		1,223	**5,239**	1,365	1,558	**2,923**	**8,162**
Washington	-	-	-			**-**	440	-	**440**	**440**
Wyoming	7,141	4,991	6,510	1,428		**20,070**	6,790	6,711	**13,501**	**33,571**
Total	52,655	21,573	43,566	3,150	2,856	**131,871**	58,456	112,432	**170,888**	**302,759**

*Arizona's first point source inventory in EDMS did not include NOx emissions. The emissions presented here will be included in a revised submission by AZ DEQ.

Note: Entries with a “-“ indicate emissions were estimated to be zero. Entries that are blank indicate that emissions for the state-source combination are not estimated in this area source portion of the inventory.

Table 2-2 compares the results of the present oil and gas inventory effort with the oil and gas emissions in the state inventories previously submitted to WRAP EDMS. Total NOx emissions estimated by this inventory of oil and gas emissions represent a 68 percent increase in inventoried oil and gas emissions. The increases in some of the main oil and gas producing states are even more dramatic. Emissions in Montana, North Dakota and Utah have increased by 195, 131 and 179 percent as a result of this effort. Oil and gas NOx emissions estimated for the State of New Mexico have increased by over 60,000 tons.

Table 2-2. Change in oil and gas emissions in the 2002 inventory as a result of this inventory effort.

State	WRAP Oil and Gas Inventory			Oil and Gas in Previous Inventory			Change in Oil and Gas Emissions	
	Area	Point	Total	Area	Point	Total	Total	Percent
Alaska	886	44,255	45,142	-	44,255	44,255	886	2%
Arizona	16	3,669	3,685	-	3,669	3,669	16	0%
California*	8,070	10,695	18,765	8,070	10,695	18,765	-	0%
Colorado	23,178	27,225	50,403	-	27,225	27,225	23,178	85%
Idaho	-	2,590	2,590	-	2,590	2,590	-	0%
Montana	7,792	3,989	11,781	-	3,989	3,989	7,792	195%
Nevada	62	120	182	-	120	120	62	52%
New Mexico	61,475	56,439	117,914	-	56,439	56,439	61,475	109%
North Dakota	4,631	3,538	8,169	-	3,538	3,538	4,631	131%
Oregon	85	1,182	1,267	-	1,182	1,182	85	7%
South Dakota	367	323	690	-	323	323	367	114%
Utah	5,239	2,923	8,162	-	2,923	2,923	5,239	179%
Washington	-	440	440	-	440	440	-	0%
Wyoming	20,070	13,501	33,571	6,409	13,501	19,910	13,661	69%
Total	131,871	170,888	302,759	14,479	170,888	185,367	117,392	63%

*Area source emissions in WRAP Oil and Gas Inventory adopted from data submitted by the California ARB.

MAJOR NOx SOURCE INVENTORY

Drilling Emission

The proposed approach for estimating emissions from drill rig engines was to use drill permit data from oil and gas commissions (OGCs) as a base measure of activity and to supplement that with more sophisticated data from drilling companies. This approach was then revised to replace the data from drilling companies with data from a survey of drilling in Southwest Wyoming. The final emission estimate uses several activity indicators from the drill permit data and combines that with emission factors derived from the Wyoming survey to make the most locally appropriate emission estimate.

In concordance with the proposed approach, we contacted large drilling companies to obtain data on the types of engines used for drilling, the normal operational schedule of the engines, regional variation of drilling rates and the relative activity of rotary versus workover rigs. The response to this survey was a mixture of refusal to participate and avoidance. Ultimately, none of the drilling companies contacted provided data to ENVIRON for this inventory effort.

Concurrent to the survey of drilling companies, we contacted State OGCs to obtain, amid other information, the activity data afforded by drill permits. The OGCs, in general, readily made the requested information available. The exception was the New Mexico Oil and Gas Conservation Commission, which declined to provide information. However, with considerable assistance from the New Mexico Air Quality Department, the necessary information was obtained for New

Mexico as well. The drilling information obtained for each State is as follows:

- Spud date - the date that drilling commenced
- Well depth - the depth of the well; total vertical, measured or target depending on availability
- Completion date - the date well preparation is finalized; occurring with some delay after drilling ceases
- Well formation - the geologic structure that the well was drilled to
- Well field - the legal designation for the area where the well was drilled
- Well county - the county where the well was drilled; for allocation purposes

The completeness of this information varied considerably from State to State. While each State maintained a database containing these fields, every field was not completed for every well. The absence of this information required that some assumptions be made about the depth of some wells drilled and the duration of drilling. Those assumptions are documented later in this section. The references for the drill permit data are provided in Table 2-3.

Table 2-3. Source of drill permit data.

States with Drilling Activity in 2002	Source of Drill Permit Data
Alaska	Alaska Oil and Gas Conservation Commission (AK OGCC), 2005
Colorado	Colorado Oil and Gas Conservation Commission (CO OGCC), 2005
Montana	Montana Board of Oil and Gas Conservation (MT BOGC), 2005
North Dakota	North Dakota Industrial Commission, Oil and Gas Division (ND OGD), 2005
New Mexico	New Mexico Environmental Department (NM ED), 2005 and New Mexico Oil Conservation Division (NM OCD), 2004
Nevada	Nevada Division of Minerals (NV DM), 2005
South Dakota	South Dakota Department of Environment & Natural Resources, Minerals and Mining Program (SD MMP), 2005
Utah	Utah Division of Oil, Gas and Mining (UT DOGM), 2005
Wyoming	Wyoming Oil and Gas Conservation Commission (WY OGCC), 2005

The databases maintained by State OGCs provided the base level of activity to characterize the number of wells being drilled in an area, the depth of those wells and the amount of time required to construct the wells. What was still needed was the more detailed information about the drill rigs that the drilling companies did not provide. That information was necessary to tie this information about the characteristics of the well being drilled to emissions from drill rig engines. Fortunately, the Wyoming Department of Environmental Quality (DEQ) was able to provide results from a recent survey of drilling in the Jonah-Pinedale area of Southwest Wyoming.

The Jonah-Pinedale area has seen particularly intense drilling activity in recent years and the information provided represents the synthesis of emissions estimates made by ten different drilling companies for a total of 218 wells drilled. The emission factors derived from the WYDEQ (2005) survey are 13.5 tons NOx per well and 3.3 tons SO_2 per well. The Colorado Department of Public Health and Environment (CDPHE) was also able to offer an emission factor. That factor was provided by only one company and without information available as to the area for which such a factor would be appropriate. Due to the larger survey size and the greater information available it was therefore the Jonah-Pinedale information that we used.

The emissions from the prime mover on a drill rig for drilling a well are dependent upon the depth of the well, the composition of substrate and the characteristics of the engine. For example, a small rig drilling a relatively shallow well in the Powder River Basin would have different emissions than a large rig drilling a deep well in the Jonah-Pinedale area. Because of this variation in drilling operations, that it would not be appropriate to use the same Jonah-Pinedale emission factor for all wells drilled in the WRAP States without making some adjustments. To reflect this fact, we developed a methodology that uses information about the characteristics of wells in a specific area to scale the Jonah-Pinedale emission factor for drilling operations in that area.

The most specific unit for which well characteristics were commonly available was the formation. Creating formation-specific emission factors offers a good degree of accuracy because the well depths and substrate encountered when drilling the same formation should be consistent. To determine if the data supported that anticipated consistency, we did a simple statistical analysis of the drilling operations at several formations. This analysis showed that while there was variation of the elapsed time between spud date and completion date within one formation, the majority of wells drilled clustered near the average time for the formation. Figure 2-1 shows the distribution for the Blanco-Mesaverde formation in New Mexico. It shows that the large majority of wells drilled in that formation were drilled in a period that clustered around approximately 65 days. This consistency within a single formation would be irrelevant if it weren't for the absence of data for some wells. By the methodology developed, the emissions from the drilling of all wells in one formation are estimated using the average duration of well preparation activities and average well depth within the formation. This is based on the assumption that wells with no information for depth or duration will, on average, be well represented by all those wells in the formation for which depth and duration were available.

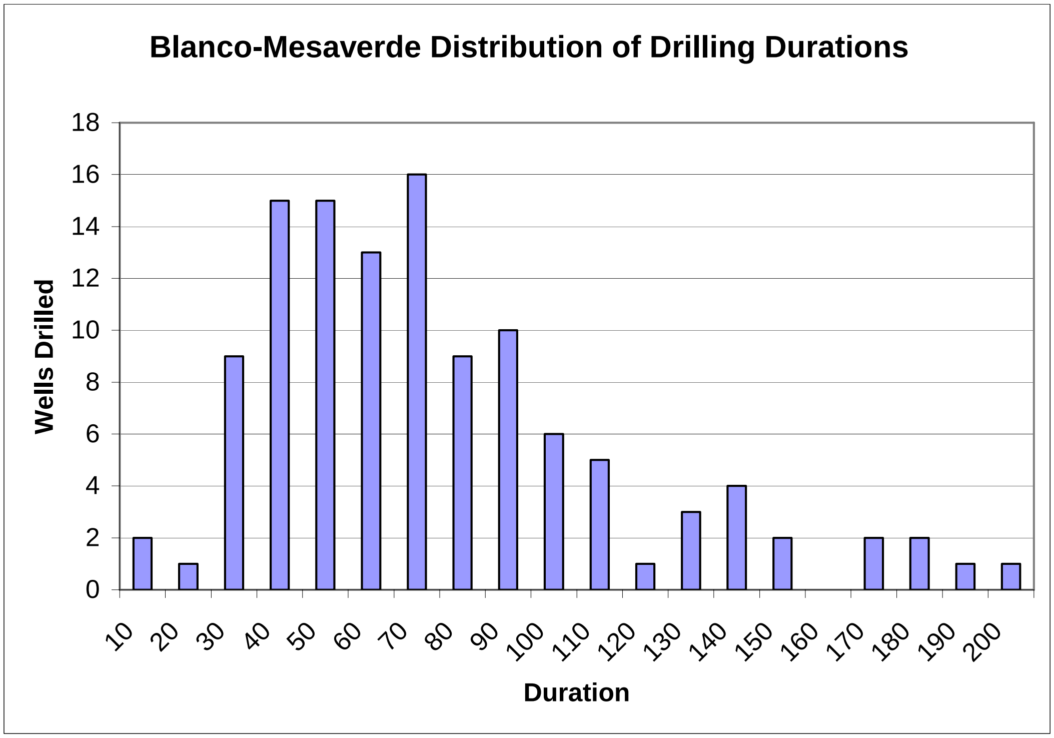


Figure 2-1. Distribution of well preparation activities within a single formation.

In addition to the assumption that the depth and duration of drilling activities for wells in a single formation are approximated by the average for the formation, two other important assumptions were made. First, it was necessary to assume that the difference between the completion date and the date that drilling ceased is, on average, constant relative to the total duration of preparation activities. This assumption was needed because the actual date that drilling ceased was not available. What this assumption means is that if on average wells with 100 days between spud date and completion actually had a duration of drilling of only 80 days, then on average wells with 50 days between spud date and completion would have 40 days of actual drilling. Though this is certainly not true on a well by well basis, it's assumed to be true for the formation averages used in this analysis.

It was also necessary to assume that the capacity of the equipment used to drill a well is dependent upon the depth of the well. This assumption was made because the data clearly indicated that substantially different rigs were employed in different drilling applications. Some wells in the Powder River Basin had the same approximate drilling duration as wells in Jonah-Pinedale. It was therefore assumed that the capacity of the prime mover would grow proportional to the depth of the well. With those two assumptions, it is then possible to scale the emission factor from the Jonah-Pinedale area to other formations based on the average well depth and drilling duration and in doing so to correct for variations due to well depth, composition of substrate, and engine capacity.

The first step in scaling the Jonah-Pinedale emission factor was to determine the appropriate average well depth and duration for the Jonah-Pinedale emission factor. The vast majority of wells drilled in Jonah-Pinedale were drilled to the Lance or Lance-Mesaverde formation. The average well depth and drilling duration for those formations - based on drill permit data obtained from the Wyoming OGC for 2002 and 2004 - was 11,896 ft and 80.6 days (WY OGCC 2005). The same type of average well depth and drilling duration was then calculated for the other formations drilled in 2002 in the WRAP States. A formation-specific emission factor was then created for each formation using Calculation 1.

Calculation 1:

$$EF_A = EF_J \times (D_A / D_J) \times (T_A / T_J)$$

where:

EF_A = *The emission factor for another formation*
EF_J = *The Jonah-Pinedale emission factor*
D_A = *The average depth of wells drilled in another area*
Dj = *The average depth of wells drilled in Jonah-Pinedale*
T_A = *The duration of drilling in another area*
T_j = *The duration of drilling in Jonah-Pinedale*

In some cases, lack of data did not permit the creation of a formation-specific emission factor. The situations where that occurred and the method used to surmount those obstacles are presented in Table 2-4.

Table 2-4. Situations where formation-specific emission factors could not be created.

Area	Problem	Solution
Wyoming	Some drilling records did not report the formation	Blank formation records were assigned to the most commonly drilled formation in the same field
South Dakota, Nevada	Not enough wells were drilled to justify a formation average	The state average depth and/or duration were used
New Mexico, North Dakota	No depths and/or durations were recorded for some formations	The state average depth and/or duration was used as a default
Montana	Formation was not available	Field averages were used

Additional adjustments were considered beyond those for well depths and durations. State DEQs were surveyed to determine if there were any control requirements for drill rigs. All State DEQs responded that controls were not required on drill rig engines. Based on that information, no adjustment for controls was necessary. It was, however, necessary to account for the varying fuel sulfur levels between different States and counties. This adjustment was actually made to the county-allocated SO2 emissions rather than to the emission factor. This was accomplished by multiplying the county SO2 emission by the ratio of that county's nonroad diesel sulfur level to the Wyoming nonroad diesel sulfur level. Fuel sulfur levels used in this adjustment are provided in Appendix C; these are the same fuel sulfur level developed for the WRAP 2002 nonroad diesel equipment emission inventory.

Emissions for a single formation were calculated using Calculation 2. The emissions for that formation were then allocated to the counties that intersected the formation based on the fraction of the total wells drilled that were drilled in each county's portion of the formation, as shown in Calculation 3.

Calculation 2:

$$E = EF \times W$$

where:

E = The 2002 emission for a given formation
EF = The formation specific emission factor
W = The number of wells drilled in the formation in 2002.

Calculation 3:

CE = E x CW / TW

where:

CE = The 2002 emissions for a given county intersected by the formation

CW = The total number of wells drilled in the county's portion of the formation

TW = The total number of wells drilled in the formation

The state total drill rig NOx and SO_2 emissions that resulted from this procedure are shown in Table 2-5. The adjustments made to the emission factors are apparent in these results. While significantly more wells were drilled in the State of Wyoming than in New Mexico, the emissions in New Mexico are higher than in Wyoming. This occurs because many of the Wyoming wells were drilled quickly and to a shallow depth, as commonly occurs for the Powder River Basin CBM wells. In contrast, the wells in New Mexico were, on average, drilled deeper and took longer to drill. Where average drill depths and durations were more comparable, such as in Colorado and New Mexico, the emissions per well are relatively close. One piece of information requested from drilling companies that was not possible to obtain from other sources was the relative activity of rotary versus workover rigs. Some of the wells drilled represented here may be permits that were granted for a workover rig. Because workover rigs do not have the same constant, heavily loaded activity profile of rotary rigs, it is estimated that this represents a slightly conservative estimate.

Table 2-5. State total drill rig emissions.

State	Wells Drilled	NOx (tons)	SO2 (tons)
Alaska	205	877	66
Arizona	-	-	-
Colorado	1,245	5,736	260
Idaho	-	-	-
Montana	463	1,044	227
North Dakota	157	1,536	358
New Mexico	935	6,653	1,446
Nevada	6	24	1
Oregon	-	-	-
South Dakota	7	36	8
Utah	126	676	147
Washington	-	-	-
Wyoming	2,959	4,991	1,220
Total	6,103	21,573	3,732

Figure 2-2 presents a map of the 2002 drilling locations. Though not every well drilled is represented here because not all records included geographic coordinates, this map clearly displays the areas where well drilling activities were focused in 2002. This map also includes those wells that were drilled on tribal lands. The State emission totals presented in Table 2-4 should be considered accurate for the geographic area defined by the State boundaries, but not necessarily to the States' jurisdiction; a small amount of those emissions in the State inventory fall under tribal jurisdiction.

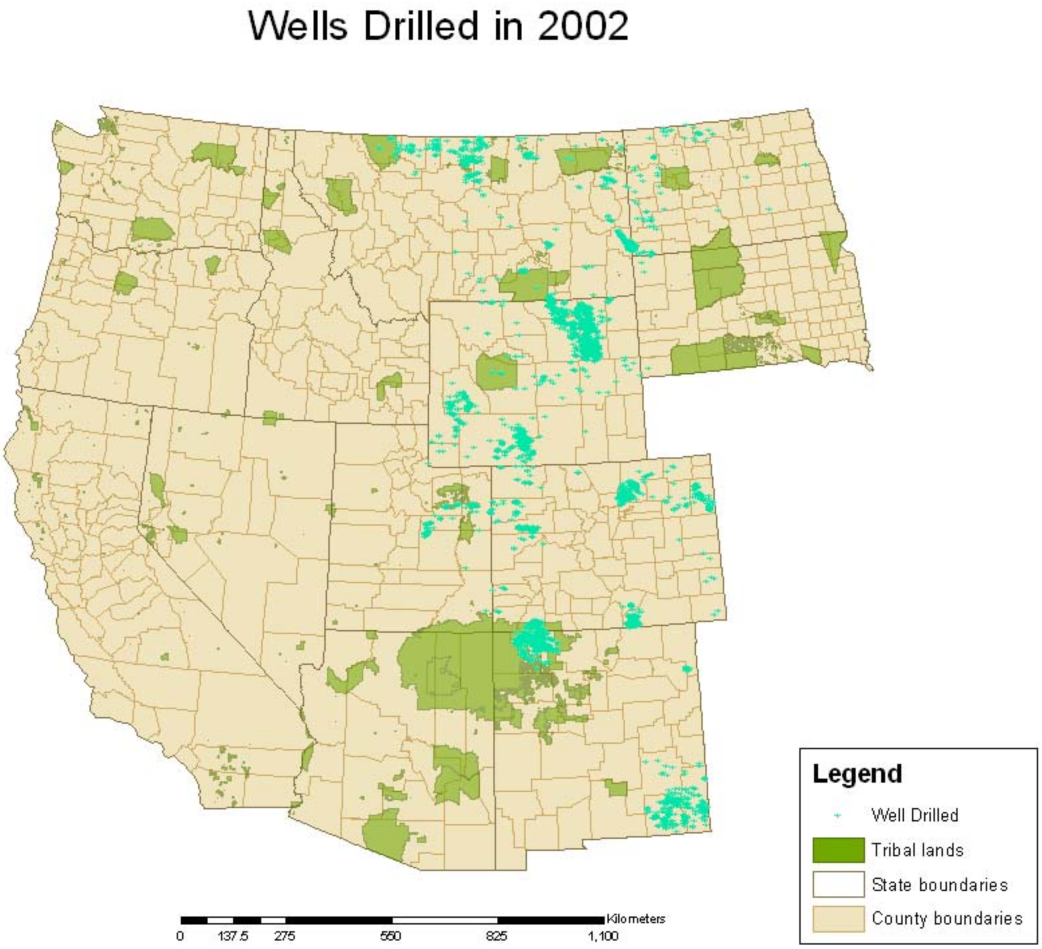


Figure 2-2. 2002 well drilling in the WRAP states.

Non-Point Natural Gas Compressor Engine Emissions

For the purposes of this study, natural gas compressor engines have been grouped into three categories. The largest facilities, in terms of potential emissions, are the large natural gas compressor stations on natural gas transmission lines. These are typically Title V facilities and they are dealt with as point sources. The second tier of facilities is the gas gathering compressor station. In most States, these too have been included in a point source emission inventory. Some exceptions, where these medium sized facilities are not in the point source inventory and have thus been included in this area source inventory are discussed in section 2.3. The final category of compressor engines, which is the primary focus of this area source compressor engine emission estimate, is the group of relatively small, dispersed wellhead compressor engines. Figure 2-3 presents an example of such an engine. In all but two of the natural gas producing States, these engines have not been included in previous emission inventories and their inclusion here represents a significant advance in understanding this important component of the oil and gas production industry. The development of a methodology to address this emissions source, the application of that methodology and a summary of results are presented in this subsection.

Figure 2-3. Wellhead compressor engine.

The preferred approach for estimating emissions from wellhead compressors that was described in the work plan focused on obtaining data from compressor operators. As was proposed, we contacted a large number of compressor operators, including exploration and production companies, gas gathering companies and compressor rental companies. This survey of operators was expected to produce, at a minimum, the number of wellhead compressors operated by each company. Also requested was information on compressor engine size, emissions data and operational schedule. Unfortunately, none of the companies contacted was willing to provide even a count of compressor engines. Repeated attempts were made to obtain data from the compressor operators, but ultimately it proved necessary to use an alternative methodology that did not rely on using data from operators.

The alternative methodology was to develop a production-based emission factor from local studies of compressor engine emissions. This emission factor was then combined with gas production data collected from the State OCGs to estimate emissions. Several local studies were analyzed to determine which offered the most appropriate data from which to derive the emission factor. The strengths and weaknesses of each of those studies and the ultimate selection of an industry-compiled inventory of wellhead compressor engines in the New Mexico portion of the San Juan Basin is discussed below.

2002 Colorado Point Source Emission Inventory

The Colorado Department of Public Health and Environment compiled a point source emission inventory for the year 2002 that includes sources with actual emissions down to 2 tons per year in attainment areas and 1 ton per year in non-attainment areas (CDPHE, 2005b). Given these exceptionally low inventory thresholds, all wellhead compressors are expected to have been included in the inventory. Gas production data was also obtained from the Colorado Oil and Gas Conservation Commission, making it appear possible to create a production-based emission factor by comparing emissions from the compressor engines in the Colorado point source inventory with gas production reported by the CO OGCC.

The extraction of only those engines used to power wellhead compressors from the point source inventory proved a more difficult task than expected. The coding of engines was such that it was difficult to distinguish between engines used for compression and engines used for other purposes such as pumping or generator sets. Nor was it possible to determine with confidence the subset of engines that represented only small wellhead compressor engines that would not be included in other States' point source inventories. This second problem represented an obstacle, because if medium-sized facilities were inadvertently included in the development of the emission factor then the resulting area source emission estimate for other States would be double-counting the emissions from medium-sized gas gathering facilities. Despite the fact that the CDPHE generously provided additional information from their records beyond what was provided in the point source inventory, it was not ultimately possible to develop an emission factor based on the Colorado point source inventory.

2002 New Mexico Oil and Gas Association's Inventory of Unpermitted Sources in the San Juan Basin

The New Mexico Oil and Gas Association (NMOGA) cooperated in the preparation of the Denver Early Action Compact by compiling an inventory for year 2002 of the unpermitted emissions sources operated by the oil and gas production industry in the New Mexico portion of the San Juan Basin. In the State of New Mexico, the threshold for permitting reported by the New Mexico Environmental Department was a potential to emit 25 tons per year (NM ED, 2005b). Thus, the inventory of unpermitted sources included those sources with a potential to emit less than 25 tons per year. The small wellhead compressor engines fall into this category. The NMOGA inventory provided emissions for wellhead compressor engines, which could be compared to production statistics for the San Juan Basin to derive an emission factor with units of tons NOx per MCF of gas produced.

The NMOGA inventory was based on a survey of exploration and production companies. The survey obtained responses representing activity at 10,582 of 17,108 wells. Emissions for wellhead compressor engines submitted by the responding companies totaled 14,892 tons NOx (NMOGA, 2003). To estimate the emissions at all wells, this emission was divided by the fraction of wells represented in the responses. This produced an estimate of 24,076 tons of NOx emitted by wellhead compression in the New Mexico portion of the San Juan Basin.

This emission estimate corresponds to gas production in three New Mexico counties: Rio Arriba, San Juan and Sandoval. Total 2002 gas production for those three counties was obtained from the on-line production database maintained by the New Mexico Institute of Mining and Technology. Production figures are summarized in Table 2-6.

Table 2-6. 2002 gas production in the San Juan Basin – New Mexico.

County	2002 Gas Production (MCF)
Rio Arriba	391,007,587
San Juan	638,024,961
Sandoval	1,420,527
San Juan Basin Total	**1,030,453,075**

(NMT, 2005)

With these estimates of total gas production and total emissions for wellhead compression, it was possible to calculate a production based emission factor as the quotient of total emissions divided by total gas production. The result is an emission factor of 2.3×10^{-5} tons NOx per MCF gas produced.

Bureau of Land Management Environmental Impact Statements

Several Bureau of Land Management (BLM) environmental impact statements (EIS) were examined for information they might provide on the relationship of gas compression and gas production. The Powder River Basin EIS included the most complete information on the anticipated compression needs for the future development of gas wells. That information, in the form of expected installed wellhead compression capacity, was combined with an EPA emission factor for natural gas fired engines, to estimate the expected emissions from natural gas fired engines. This estimate was then compared to the estimated gas production to develop a production-based emission factor.

The Powder River Basin EIS estimated that 380 horsepower of installed compression capacity would be required for every 250 MCF-day of new gas production (BLM, 2002). Assuming 8,760 hours per year of gas production and hence compressor operation, this equates to 3,328,800 horsepower-hours per year for 91,250 MCF of gas production. Applying the 12 grams NOx/hp-hr emission factor for Light Commercial Gas Compressors (SCC2268006020) from the EPA's NONROAD2004 emissions model, this compressor activity would result in 44 tons of NOx. Dividing this result by the associated production, 91,250 MCF, results in a production-based emission factor of 4.8×10^{-4} tons NOx per MCF.

The emission factor derived from the BLM EIS is based on the fundamental assumption that 380 horsepower of compression will be added for every 250 MCF-day of gas production. Supporting evidence for this assumption is not provided in the Powder River Basin EIS. The EIS is a forecast of production and equipment that may be installed, not a study of existing operations. Although it provides sufficient information to calculate the necessary production-based emission factor, these limitations would not allow us to place a high degree of confidence in the estimates produced by that emission factor.

East Texas 2002 Emission Inventory

The emission inventory prepared for the Tyler/Longview/Marshal Flexible Attainment Region of East Texas included an estimate of the emissions for area source compressor engines. The method used by the contractor, Pollution Solutions (2005), to estimate gas compressor emissions was to develop a relationship between compressor engine activity and gas production from a survey of compressor operators. That relationship was then used with gas production statistics and EPA emission factors to estimate engine emissions.

The survey of operators yielded a relationship of 191 horsepower of compression per MMSCF-day of gas production. Assuming 8760 hours per year of operation, as was done in the East Texas Inventory, this results in 1,673,160 hp-hr/year per MMSCF-day. Converting that figure to an activity factor based on annual gas production gives 4,584 hp-hr per MMSCF or 4.58 hp-hr per MSCF. Combining that with the 11 g NOx/hp-hr emission factor used by Pollution Solutions results in a production-based emission factor of 5.6×10^{-5} tons NOx per MCF.

The emission factor derived from the results of the East Texas survey seemed a good candidate for use in the present study. It was derived from actual operations and falls between the factors derived from the NMOGA inventory and the BLM EIS. However, Pollution Solutions was unwilling to provide the details of the survey that resulted in the emission factor used in the East Texas work. Without supporting documentation and technical basis we could not use the resulting emission factor.

Compressor Engine Emission Estimate

The results of the review of compressor engine studies are summarized in Table 2-7. The attempt to derive an emission factor from the Colorado 2002 Point Source Inventory was unsuccessful. The use of BLM EIS was ruled out due to the speculative nature of the production-compression relationship used in that study. Nor did it seem possible to use the emission factor derived from the East Texas Inventory in the absence of supporting evidence. We therefore decided to use the emission factor derived from the New Mexico Oil and Gas Association's Inventory of Unpermitted Sources in the San Juan Basin. This study has several advantages over the other studies. It is a study of existing operations in an important production area of the WRAP States and the survey of compressor operators attained a very high response rate. With a production-based emission factor of 2.3×10^{-5} tons NOx per MCF of gas production, it was then possible to estimate emissions based on gas production statistics obtained from the oil and gas commissions.

Table 2-7. Summarized results of review of compressor engine studies.

Source	Emission Factor (tons NOx / MCF)	Advantages	Disadvantages
CO Inventory	Inconclusive		
NMOGA Inventory	2.3x10-5	• Very good coverage/response • Important WRAP production area	
BLM Powder River EIS	4.4x10-4	• Important area of growth	• Projected, not actual equipment and production
East Texas EI	5.6x10-5	• Based on survey data • Resulting EF falls between NMOGA and BLM factors	• Lack of supporting evidence

We had previously requested from the OGCs well specific-oil and gas production statistics. These were obtained, either submitted by the OGC or downloaded from the on-line production statistics maintained by some States OGCs, for all oil and gas producing States. For the compressor engine emissions estimate, total 2002 natural gas production was summed for each county and county level emissions were estimated as the product of natural gas production (MCF) and the production-based emission factor.

The only States that reported requiring controls on compressor engines were Utah and Wyoming. In both of those States, the emissions are controlled to a rate of 1-2 grams NOx /hp-hr (WY DEQ, 2005c; UT DEQ, 2005). This represents a substantial reduction from the average emission rate of 11.4 grams NOx/hp-hr that was found by the NMOGA Inventory. The production-based emission factors for Utah and Wyoming have been adjusted downward to account for this difference. In both States, the controlled emission factor was calculated as the product of the uncontrolled emission factor, 2.3×10^{-5} ton NOx/MCF, and the ratio of controlled hourly emissions to uncontrolled hourly emissions, 2 grams NOx/hp-hr to 11.4 grams NOx/hp-hr. A summary of compressor engine controls reported by State agencies and the control-adjusted emission factors are presented in Table 2-8.

Table 2-8. State controls on compressor engines and controlled emission factors.

State	Reference	Control Requirement	Emission Factor (ton NOx/MCF)
Alaska	AK DEC, 2005b	NA[1]	
Colorado	CDPHE, 2005b	NA[1]	
Montana	MT DEQ, 2005	None	2.3×10^{-5}
New Mexico	NM ED, 2005b	None	2.3×10^{-5}
Nevada	NV DEP, 2005	None	2.3×10^{-5}
North Dakota	ND DH, 2005	None	2.3×10^{-5}
South Dakota	NV DENR, 2005	None	2.3×10^{-5}
Oregon	OR DEQ, 2005	None	2.3×10^{-5}
Utah	UT DEQ, 2005	Controlled to 1-2 g NOx/hp-hr	4.1×10^{-6}
Wyoming	WY DEQ, 2005c	Controlled to 1-2 g NOx/hp-hr	4.1×10^{-6}

[1] Any controls required on compressor engines are included in the point source inventory.

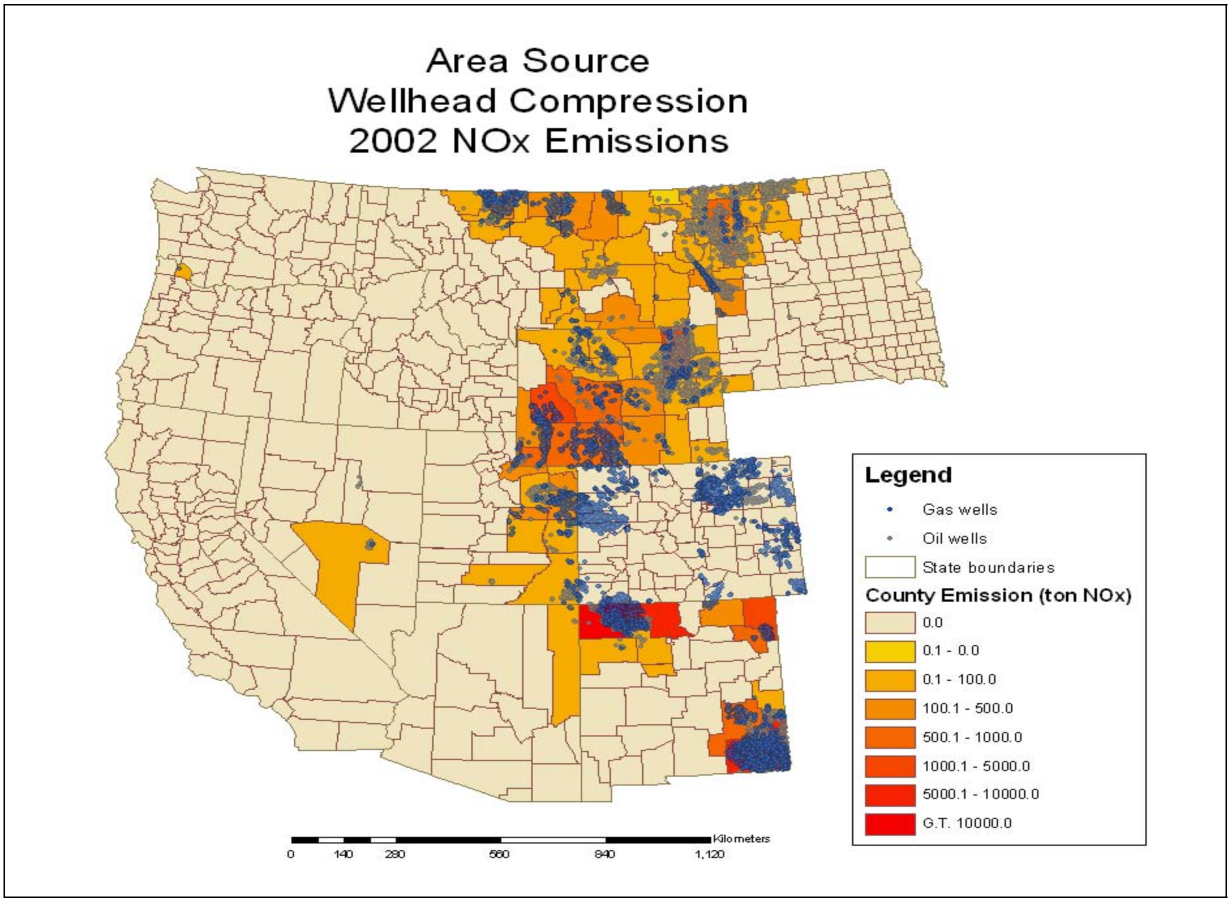
The State total NOx emissions that resulted from the application of these emission factors are presented in Table 2-9. As is shown in Table 2-9, and graphically displayed in Figure 2-4, emissions resulting from this procedure are directly related to production. Though at the level of individual wells it may be true that compressor activity is actually higher at less productive wells, when county level production is considered, as in this study, this positive correlation of compressor engine emissions to gas production is supported by all of the studies considered in the development of this methodology.

There are two exceptions to this wellhead compressor engine emissions estimate. Those are the State of Alaska and the State of Colorado. As was mentioned in the preceding discussion of the compressor engine emission factors, the State of Colorado included in its point source inventory all sources with actual 2002 emissions greater than 2 tons. This is expected to include all compressor engines. An area source emissions estimate for compressor engines was therefore not made for the State of Colorado.

In the State of Alaska, oil and gas production facilities differ dramatically from those found in the other WRAP States. In Alaska, both personnel in the State's environmental department and the oil and gas conservation commission indicated that facilities are arranged in a 'wagon wheel'. At the hub of the facility is the large processing plant, and each spoke reaches out to the production wells. Along the spokes and at the wellhead, there is emissions-producing equipment. However, this equipment is permitted along with the processing plant (AK OGCC, 2005b; AK DEC, 2005b). Wellhead compressor engines would therefore be included along with the equipment in the processing plant as a point source in the 2002 Alaska point source emissions inventory. For that reason, area source compressor engine emissions are not made for the State of Alaska.

Table 2-9. State total NOx emissions from gas compressor engines.

State	Total Gas Produced (MCF)	Emission Factor (tons NOx/MCF)	Total 2002 NOx Emission (tons)
Alaska	3,496,429,130	NA	
Arizona	304,303	2.3E-05	7.1
Colorado	1,242,774,839	NA	
Idaho	-		
Montana	86,761,832	2.3E-05	2,027.1
Nevada	6,433	2.3E-05	0.2
New Mexico	1,738,603,976	2.3E-05	40,620.9
North Dakota	59,979,925	2.3E-05	1,401.4
Oregon	837,067	2.3E-05	19.6
South Dakota	10,955,008	2.3E-05	256.0
Utah	287,399,796	4.1E-06	1,181.6
Washington	-		
Wyoming	1,736,994,398	4.1E-06	7,141.4
Total			52,655.1



*Colorado wellhead compressor emissions are in the point source inventory
**California ARB has provided separate estimates of area source oil and gas emissions

Figure 2-4. County level gas compressor engine emissions.

Medium-Sized Facilities

The emission factor developed for the wellhead compression estimate was directed at estimating emissions from sources with a potential to emit less than 25 tons per year. This was the type of source considered by the NMOGA inventory. This proved convenient, as in many States, sources with a potential to emit greater than 25 tons per year were reported by the State DEQ to be included in the point source emission inventory. However, this was not the case in all States. A summary of the State inventory thresholds is presented in Table 2-10.

Table 2-10. State point source inventory thresholds.

State	Point Source Inventory Threshold	Reconciliation	Source
Alaska	PTE 100 TPY	Smaller wellhead equipment reported to be grouped under these large facilities	AK DEC, 2005b
Arizona	PTE 40 TPY	Determined that all medium sized facilities exceeded PTE 40 TPY	AZ DEQ, 2005
Colorado	2 TPY actual emissions	Removed compressor, condensate tank and glycol dehydrator emissions from area source inventory	CDPHE, 2005b
Montana	PTE 25 TPY		MT DEQ, 2005
New Mexico	PTE 25 TPY		NM ED, 2005b
North Dakota	PTE 100 TPY	Used State’s internal inventory of compressor stations to include sources with a PTE between 25 and 100 TPY	ND DH, 2005
Nevada	PTE 5 TPY	No wellhead compressor engines included in State’s inventory. No reconciliation required	NV DEP, 2005
Oregon	PTE 100 TPY	Obtained inventory of compressor stations with PTE less than 100 TPY from State	OR DEQ, 2005
South Dakota	PTE 100 TPY	Created scaling factor based on NM point inventory and gas production	SD DENR, 2005
Utah	PTE 100 TPY	Created scaling factor based on NM point inventory and gas production	UT DEQ, 2005
Wyoming	PTE 25 TPY		WY DEQ, 2005c

As shown in Table 2-10, Montana, New Mexico and Wyoming all included sources with a potential to emit 25 tons per year or greater in their point source inventories. The State of Alaska and the State of Colorado have different inventory thresholds, but this did not require any reconciliation of the area source compression emission estimate as in those States wellhead compression is included entirely in the point source emission inventory.

In Arizona, Nevada, Oregon and North Dakota, Utah and South Dakota, the fact that the States’ inventory thresholds differed from the New Mexico PTE 25 tpy threshold required special treatment. Discussion with staff at the Arizona and Nevada DEQ revealed that despite the different thresholds, no further action was necessary. In Arizona, there were no compressor facilities with a potential to emit between 25 tpy and 40 tpy (AZ DEQ, 2005). In Nevada, despite the relatively low inventory threshold, no wellhead compressor engines had been included in the point source inventory (NV DEP, 2005).

In Oregon and North Dakota, State DEQ personnel indicated that there were oil and gas facilities that fell below the State point source inventory threshold, but were larger facilities that would not be accounted for in the area source wellhead compression estimate. Despite their exclusion from the point source inventory, both Oregon and North Dakota did have internal emissions estimates for these medium-sized facilities. Those emissions data were obtained from the State and have been included in the area source emission inventory (see Table 2-13).

In Utah and South Dakota, there existed the same gap between the wellhead compression emissions and the state point source inventory as in Oregon and North Dakota. However, in Utah and South Dakota it was not possible to obtain emissions data from the State agencies. It was therefore necessary to estimate emissions for this group of facilities based on the gas production in those States. This was done by selecting the subset of point source facilities from the New Mexico point source inventory that had a potential to emit between 25 and 100 tons per year, relating those facilities to New Mexico gas production and then scaling the emissions from those facilities to gas production in Utah and South Dakota.

The facilities in New Mexico with a potential to emit between 25 and 100 tons per year were identified by first extracting only facilities coded with an oil and gas SIC; the SIC used are listed in Table 2-11. The next step was to calculate the potential to emit for each emission unit included in those oil and gas facilities. This was accomplished by scaling the emissions reported for the unit up to what they would be if the unit had been operated 8760 hours per year. For example, if a unit in the inventory had emissions of 10 tons NOx, but had only operated 4000 hours, then the potential to emit for that unit was calculated as the product of 10 tons NOx and 8760/4000. In this case the potential to emit would then be 21.9 tons NOx. Though we acknowledge that factors other than the total hours of operation may be used in the determination of potential to emit, the detailed determination of potential to emit for each emission unit was not possible given the available resources. After estimating the potential to emit as described for each emission unit, the facility total PTE was then calculated by summing the PTE of all units in that facility. Those facilities with a total PTE under 100 tpy were extracted.

Table 2-11. Oil and gas SIC.

SIC	Description
1311	Crude Petroleum and Natural Gas
1321	Natural Gas Liquids
1382	Oil and Gas Field Exploration Services
1389	Oil and Gas Field Exploration Services, NEC
4612	Crude Petroleum Pipelines
4922	Natural Gas Transmission
4923	Natural Gas Transmission and Distribution
4925	Mixed, Manufactured or Liquefied Petroleum Gas Production

Using the information in the New Mexico inventory, it was possible to separate the facilities with a PTE between 25 tons per year and 100 tons per year into two categories: gas compression and gas processing. The total emissions in each of these categories were then summed to determine the State total emissions. By dividing those totals by the State total gas production we arrived at the production-based emission factors shown in Table 2-12.

Table 2-12. Emissions for New Mexico natural gas facilities with a PTE between 25 and 100 tpy.

Type of Facility	Gas Processing	Gas Transmission
Total Emissions (tons NOx)	2,715	4,195
Total Gas Production (MCF)	1,624,225,738	
Emission Factor (ton NOx/MCF)	1.67×10^{-6}	2.58×10^{-6}

Combining the emission factors in Table 2-12 with the county gas production in Utah and South Dakota, we estimated emissions for the medium-sized gas processing and transmission facilities in those states. Using these emissions estimates and the emissions provided by State agencies for Oregon and North Dakota, we have supplemented the area source emissions estimates for those States to include the facilities with a potential to emit between 25 and 100 tons per year. Also included in this supplement is a compression facility in Clark County, Nevada. Although no action was required to reconcile the inventory prepared by the State of Nevada, Clark County submitted its own inventory in which it grouped a compressor facility in with other sources of natural gas combustion. We obtained emissions for this source and have included it in the oil and gas area source emission inventory. The State total emissions for these facilities are shown in Table 2-13.

Table 2-13. Area source emissions estimate for facilities with a PTE between 25 and 100 tpy.

State	Medium Facility Emissions (tons NOx)	Source
Oregon	53.8	OR DEQ, 2005
North Dakota	1,518.4	ND DH, 2005
Utah	1,222.6	Estimated
South Dakota	28.3	Estimated
Nevada	33	CC DAQM, 2005

Coal Bed Methane Generators

The methodology described in the work plan for estimating emissions from coal bed methane generators relied on obtaining information on generator specifications and usage from State environmental departments. Based on the map of CBM production obtained from the Energy Information Administration (Figure 2-5), environmental departments were contacted for this information in five States: Colorado, Montana, New Mexico, Utah and Wyoming. Of those, only Wyoming was able to provide information on the generators associated with CBM wells (WYDEQ, 2004; WYDEQ, 2005b). Contacts in Montana and Utah indicated that the CBM fields in their states are electrified and pumps are expected to be operated on line power (Richmond, 2005; Daniels, 2005). Therefore it remained to determine generator usage in only Colorado and New Mexico.

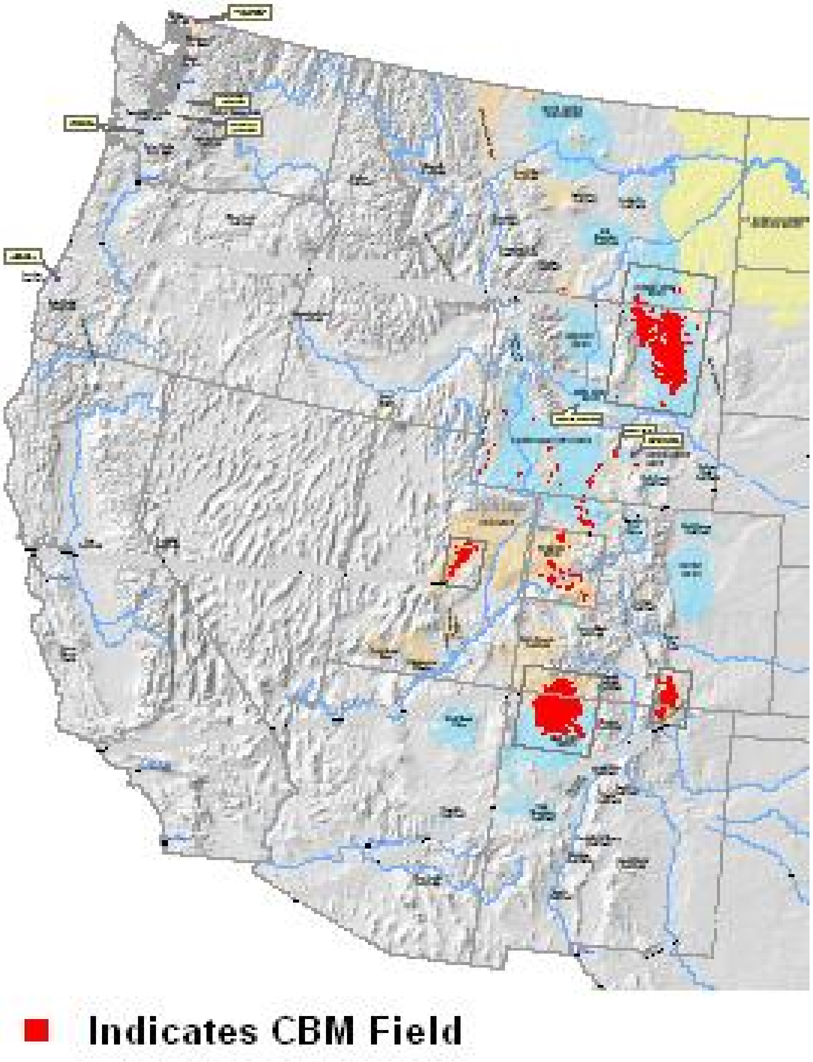


Figure 2-5. Map of US Coal Bed Methane Production. (EIA, 2004)

While contacting the State environmental departments to obtain data on generators, we also requested production data from OGCs in each of the WRAP States. In the States with CBM production, that data included the water production at CBM wells. In addition, the depth of wells was obtained for some sampling of the wells in each State; depth information was not available for every well. Based on the data available, the first emission estimate that we produced was the result of scaling the generator activity obtained for the State of Wyoming to the other CBM producing states based on the average depth of wells and the water produced at CBM wells. This scaling was made based on the understanding that the work performed by generators is correlated to the mass of water lifted by pumps and the distance over which it must be lifted.

The emissions produced by this first methodology did not appear sufficient to represent the activity at the large number of CBM wells in Colorado, New Mexico and Wyoming. The emissions determined by this method, on a per well basis, for these three States were 0.080, 0.010 and 0.067 tons NOx respectively. One possible explanation for the surprisingly low results determined by this method is that the generator information obtained from the State of

Wyoming excluded some of the engines, possibly those that are directly coupled to CBM pumps. Also, actual hours of operation were only available for a subset of the generators. Activity of the remaining generators in Wyoming was extrapolated from the activity of that subset. It's possible that the activity of the subset was not representative of the entire population of generators. In summary, engineering calculations showed that a great deal more work would be performed in dewatering CBM wells than was suggested by this emissions estimate based on the WYDEQ emissions factors.

Operating under the assumption that the database of generators obtained from the Wyoming DEQ may not include all the engines associated with dewatering, it was necessary to develop an emissions estimation methodology where activity could be determined based only on the well production data obtained from the State OGC. Information on the design and operation of CBM wells in combination with engineering calculations provided a way to estimate engine activity (horsepower-hours) based on water production. Once horsepower-hours were estimated, it was then possible to derive an emission estimate using an emission factor from EPA's NONROAD2004 emissions model.

Estimating Engine Activity

Engine activity was determined for each well by first determining the water power developed by the dewatering pump. Using an assumption of the pump's efficiency it was then possible to determine the power that must be supplied to the pump. Assuming that losses in the electrical delivery system are negligible, the power supplied to the pump is the same as the power produced by the generator. Then, by estimating the efficiency of the generator system at converting the power at the engine flywheel to electrical power it was possible to estimate the horsepower-hours of the engine. This was then combined with an emission factor to determine emissions resulting from the dewatering of each well. The complete list of assumptions used for this calculation are presented in Table 2-14.

Table 2-14. Assumptions used in developing the CBM generator emissions estimate.

Assumption	Reason
Pumping in NM and CO is done by natural gas fired engines. Pumping in WY is done with a mix of natural gas and diesel engines.	The Wyoming generator data shows that the majority of the generator horsepower is natural gas fired (WY OGCC, 2005b). Also, industry representatives indicate that use of electric power from the grid is minimal (Gantner, 2005).
Pump efficiency = 0.6	Industry provided estimate (Olson, 2004).
Generator efficiency = 0.85	Estimate based on small size of engines.
Downhole pressure contribution is negligible	Simplification necessary due to lack of data. This leads to a slightly conservative estimate.
Power delivered the pump is exactly equal to the power required to lift water over the depth of the well and overcome frictional losses. Minor losses (joints, flanges, etc...) and exit velocity are assumed to be negligible	The power in lifting the water is undoubtedly much greater than any of the other components. No data available on minor losses and exit velocity.
Diameter of pipe that conducts water to surface is 0.2 ft	Wyoming OGC provided estimate (Strong, 2005)
Pipe roughness of drawn/plastic tubing (5x10-6 ft)	Industry contact stated majority of piping is fiberglass (Weatherford, 2005)
8760 hours of engine operation and 4380 hours of pumping per year	Industry representative indicated that much of the time the engine is operating, but no water is being pumped (Gantner, 2005).

Information from State OGC and industry contacts enabled us to define the relevant portions of the design of the average coal bed methane well. The most common pipe size reported to be used by a pumping system supplier, 2 and 3/8 inch, coincided with what the Wyoming OGC reported to be a common pipe size on permit applications (Weatherford, 2005; Strong, 2005). A representative of one production company operating in Wyoming reported that the vast majority of the pumps it used (over 90 percent) are electric submersible pumps (ESP) with an approximate efficiency of 60 percent (Olson, 2005). Though producers in other areas, such as the San Juan Basin and the Raton Basin, have reported predominantly using other types of pumps, including plunger lifts, progressing cavity pumps and rod lift systems, the 60 percent efficiency estimate has been used for all areas. Manufacturer information indicates that the ESP is the least efficient type of pump and therefore this results in a conservative estimate (Weatherford, 2005b). A simple diagram of the assumed pumping system that results from this information is provided in Figure 2-6.

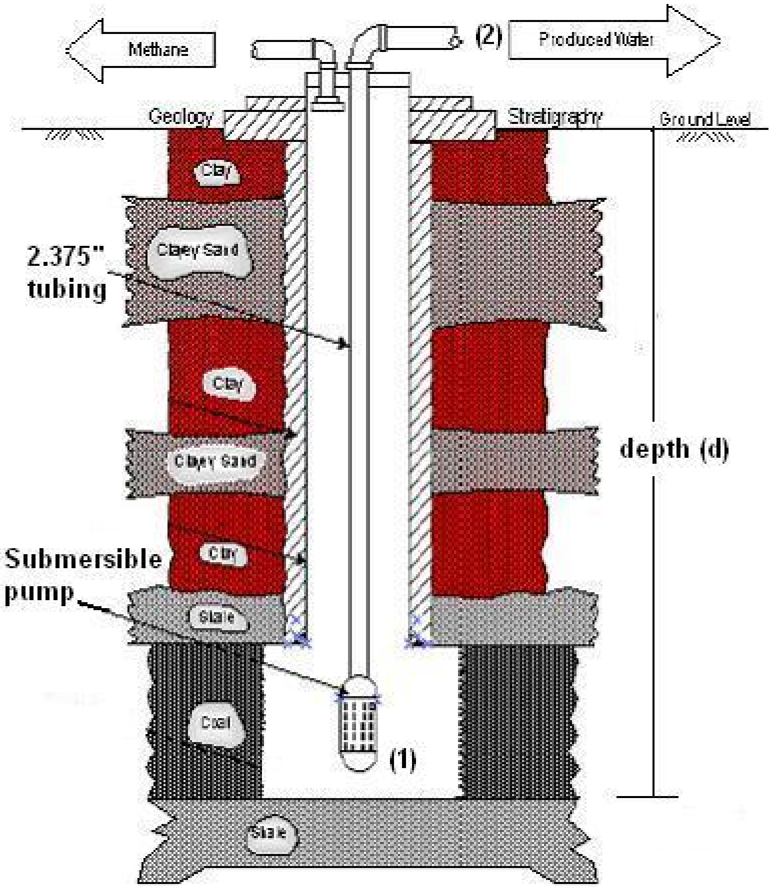


Figure 2-6. Diagram of assumed CBM well.

With the assumption that minor losses from joints in the pipe or other inconsistencies in the system are negligible and that the exit velocity at the top of the pipe is near zero, then the power imparted to the water by the pump is equal to the power required to overcome the elevation difference and the "frictional losses" (the energy lost to heat and turbulence at the pipe-water interface). This system can be described using a form of the Bernoulli equation, where the energy at the exit of the pipe (labeled "2" in Figure 2-6) is equal to the sum of the energy at the inlet to the pump (labeled "1" in Figure 2-6) plus the energy supplied by the pump and the frictional losses as shown in Calculation 4.

Calculation 4. Modified Bernoulli equation

$$z_1 + \frac{P_1}{\gamma} + \frac{v_1^2}{2g} + H_P - H_L = z_2 + \frac{P_2}{\gamma} + \frac{v_2^2}{2g}$$

where:

z = Elevation
P = Pressure
γ = Specific weight of water, 62.4 lb/ft^2
ν = Velocity
H_p = The head imparted by the pump (feet)
H_L = The head lost to friction (feet)

If the exit velocity is excluded and the downhole pressure assumed to be negligible, then the above equation reduces to:

$$z_1 + H_P + H_L = z_2$$

rearranging and substituting the depth (d) for z_2 - z_1 shows that the energy imparted by the pump, H_p, is given by:

$$H_P = d + H_L$$

H_L is somewhat difficult to calculate due to the dependence of the calculation method on the flowrate. For the same pipe under a certain threshold flowrate, the flow is laminar and it is a simple matter to determine the frictional loss using the Darcy-Weisbach equation. However, above that threshold flowrate for the same pipe, the flow becomes turbulent and there are several possible methods of estimating the frictional loss. In this study, we have used the Hazen-Williams equation to estimate frictional losses for flowrates that imply a Reynolds Number above 3000 (see Calculation 5).

The flowrate itself is not a trivial matter to estimate. The information obtained from the State OCD is total annual water production. One option was to assume that flow is constant for 8760 hours per year. However, based on information generously provided by Bruce Gantner (2005) of the New Mexico Oil and Gas Association, it was clear that pumps are frequently operating without pumping any fluid apart from gases. This would occur when the water level in the well is drawn down low enough that water needs to be pumped only intermittently. Effectively, this signifies that a portion of the time the engines are operating with a very low load when no water is being pumped and the rest of the time are operating at a load sufficient to pump water. At this time, it has not been possible to estimate the fraction of time that the pumps are actually moving water and fifty percent has been assumed. This means that fifty percent of the time engines are assumed to be idling with only ten percent of their loaded horsepower. These idling emissions, discussed below, are added to the emissions resulting from the work performed to lift water from the wells. In terms of the determination of flowrates, this 50 percent operational schedule means that flowrates are determined based on the total annual water production divided by 4,380 hours per year of pumping.

Calculation 5. Method for calculating the frictional losses (H_L)

$$R = \frac{D \times V}{\nu}$$

where:

R = The Reynolds number
D = The diameter of the pipe
V = The velocity of flow (flowrate divided by cross-sectional area of pipe)
ν = The kinematic viscosity of water (assumed = 1.0)

If R < 3000 then,

$$H_L = f \times \frac{L}{D}\frac{V^2}{2g} \qquad \text{(the Darcy-Weisbach equation)}$$

where
L = The length of pipe
D = The diameter of pipe
V = The velocity of flow
g = The acceleration of gravity

and with

$$f = \frac{64}{R}$$

Else if R > 3000,

$$H_L = \frac{V^{1.85} L}{(1.318 \times C_H)^{1.85} \times R^{1.17}} \qquad \text{(the Hazen-Williams equation)}$$

where:

V = The velocity of flow
L = The length of pipe
R = The hydraulic radius (cross-sectional area of pipe divided by the wetted perimeter)
C_H = The Hazen-Williams coefficient, 140 for plastics

As shown in calculations 4 and 5, determining the frictional loss and adding that to the depth of the well yields the energy that is imparted by the pump. Then, to determine the power of the pump we apply the equation shown in Calculation 6.

Calculation 6. Determining the pump power

$$P = H_P \times Q \times \gamma / 550$$

where

P = the power supplied by the pump (hp)
H_P = the energy supplied by the pump (ft)
Q = the flowrate (cfs)
γ = specific weight of water (62.4 lb/ft^2)

Once the power delivered by the pump was determined, determining the power developed by the engine was a matter of applying the pump and generator efficiencies as shown in Calculation 7.

Calculation 7. Determining the engine power

$$P_E = P / \varepsilon_P / \varepsilon_G$$

where

P_E = the power developed by the engine (hp)
P = the power delivered by the pump (hp)
ε_P = the efficiency of the pump (0.60)
ε_G = the efficiency of the generator (0.85)

Total annual engine activity due to pumping water at one well was estimated as the product of the power developed by the engine and 4,380 hours per year. To this activity, with units of horsepower-hours, was added the engine activity while not pumping water. Engines that are idling while no water is being pumped are assumed to operate at ten percent of their operational load. Thus, for a single well, the idling engine activity was calculated as ten percent of the pumping horsepower determined in Calculation 7 multiplied by 4,380 hours per year. The total engine activity was thus the sum of 4,380 hours of engine activity while idling plus 4,380 hours of engine activity while pumping. Emissions were then calculated in New Mexico and Colorado as the product of total engine activity and the 12 g/hp-hr emission factor for natural gas fired engines (SCC 2268006005) provided in EPA's NONROAD (2004). For Wyoming, an emission factor was developed that reflected the controls imposed by WYDEQ on natural gas fired engines and the use of some diesel generators to power pumps. That emission factor is 6.1 g/hp-hr.

The total emissions estimated by this method for Colorado, New Mexico and Wyoming are presented in Table 2-15. This method has resulted in per well NOx emissions for these three states of 0.59 tpy/well in Colorado, 0.06 tpy/well in New Mexico and 0.23 tpy/well in Wyoming. This represents a significant increase over the emissions predicted by the previous method, 0.080

tpy/well, 0.010 tpy/well and 0.067 tpy/well respectively. Despite having a large number of wells, New Mexico's emissions from CBM engines are substantially less than in Colorado and Wyoming. This is a result of the relatively low water production in New Mexico. This low water production implies less work is done by engines. Industry representatives indicated that the San Juan Basin, where most coalbed methane production occurs in New Mexico, is a mature field where at this point comparatively little dewatering is necessary (Gantner, 2005).

Table 2-15. State total NOx emissions from coalbed methane engines.

State	CBM Wells	Engine Emissions - Pumping (ton/yr)	Engine Emissions - Idling (ton/yr)	Total Engine Emissions (ton/yr)
Colorado	2,535	1,354	135	1,489
New Mexico	3,752	213	21	234
Wyoming	12,147	2,552	255	1,428

VOC AND MINOR NOx SOURCE INVENTORY

In addition to the area sources identified as potentially major sources of NOx emissions, we have estimated emissions for several other processes occurring at oil and gas wellheads. Emissions were estimated for both NOx and VOC using well-specific production and emission factors provided by the Wyoming Department of Environmental Quality and the Colorado Department of Public Health and Environment. The sources for which emissions were estimated in this portion of the inventory are listed in Table 2-16.

Table 2-16. Emissions sources estimated in the VOC and minor NOx source inventory.

Process	Pollutants	Emission Factors Units
Tanks - Flashing & Standing/Working/Breathing	VOC	lbs per year/barrel per day of condensate production
Glycol Dehydration Units	VOC	lbs per year/million cubic feet per day of gas production
Heaters	NOx, CO	lbs per year/well site
Pneumatic Devices	VOC	tons per year/well
Completion - Flaring and Venting	VOC, NOx, CO	tons/completion

As proposed in the work plan, the default emission factors used for these sources were the emission factors provided by the Wyoming DEQ (2004b). State agencies and industry were given the option of providing their own emission factors. Only the CDPHE (2005) provided alternate emission factors. The emission factors used are presented in Table 2-17.

Table 2-17. Wyoming DEQ emission factors.

Gas Wells	**Emission Factor**	**Oil Wells Source**	**Emission Factor**
Condensate Tanks	3,271 lbs VOC per year/BPD	Heater	0.005 lbs NOx per barrel
Dehydrator	27,485 lbs per year/MMCFD	Pneumatic Devices	0.1 tons VOC / well
Heater	1,752.0 lbs NOx per year/well	Tanks	160.0 lbs VOC per year / BPD
Completion	86.0 tons VOC/well completion		
	1.75 tons NOx/well completion		
Pneumatic Devices	0.2 tons VOC per year/well		
CDPHE Emission Factors			
Completion	16.664 ton VOC/well completion		
	0.85 ton NOx/well completion[1]		

[1] Though the CDPHE only provided an emission factor for VOC, we have used the assumptions used by the CDPHE to prepare that emission factor in order to develop an appropriate NOx emission factor.

[2] For documentation of the Wyoming DEQ emission factors, refer to Appendix A.

To use these emission factors, it was necessary to obtain well-specific production data from the State oil and gas commissions. In most cases, the necessary data was either compiled by the oil and gas commission and submitted to ENVIRON or was downloaded from the oil and gas commission's website. The list of well-specific information obtained from the oil and gas commissions is presented in Table 2-18. The list of sources for this production data is similar to the list of sources of drill permit data, but is included here as Table 2-19 for completeness.

Table 2-18. Well-specific data obtained from the oil and gas commissions.

2002 oil produced
2002 gas produced
2002 water produced
well location (latitude/longitude)
well field
well formation
well depth
well class (oil/gas)
coal bed methane (yes/no)
completion date

Table 2-19. Sources of well-specific production data.

States with Oil/Gas Production in 2002	Source of Production Data
Alaska	Alaska Oil and Gas Conservation Commission (AK OGCC), 2005
Arizona	Arizona Geological Survey (AZ GS), 2005
Colorado	Colorado Oil and Gas Conservation Commission (CO OGCC), 2005
Montana	Montana Board of Oil and Gas Conservation (MT BOGC), 2005
North Dakota	North Dakota Industrial Commission, Oil and Gas Division (ND OGD), 2005
New Mexico	New Mexico Environmental Department (NM ED), 2005 and New Mexico Oil Conservation Division (NM OCD), 2004
Nevada	Nevada Division of Minerals (NV DM), 2005
Oregon	Oregon Department of Geology and Mineral Industries (OR DGMI), 2005
South Dakota	South Dakota Department of Environment & Natural Resources, Minerals and Mining Program (SD MMP), 2005
Utah	Utah Division of Oil, Gas and Mining (UT DOGM), 2005
Wyoming	Wyoming Oil and Gas Conservation Commission (WY OGCC), 2005

The fact that records were obtained for all wells that contained each of the fields in Table 2-18 did not mean that for every well all those fields were populated. The most important fields for the purposes of this inventory were those containing the production figures. These appeared to be well maintained. However, in some cases the completion date and the well class, which are also used in this emission estimate, were blank. It did not appear possible to obtain additional data for completion dates, and the assumption is that a blank completion date implies the well was completed some time in the past, prior to 2002.

The data provided by the State of Colorado Oil and Gas Commission presented the most difficulty due to the absence of data specifying whether a well was considered an oil or gas well. This information was necessary because the emission factors shown in Table 2-17 were determined specifically for oil wells or gas wells (WYDEQ, 2004b). In order to proceed, it was necessary to divide the wells into these two categories. For the State of Colorado this was accomplished by calculating the ratio of gas production (MCF) to oil production (BBL) for all wells and then determining where an appropriate division would be. The distribution of wells according to their gas oil ratios is presented in Figure 2-7.

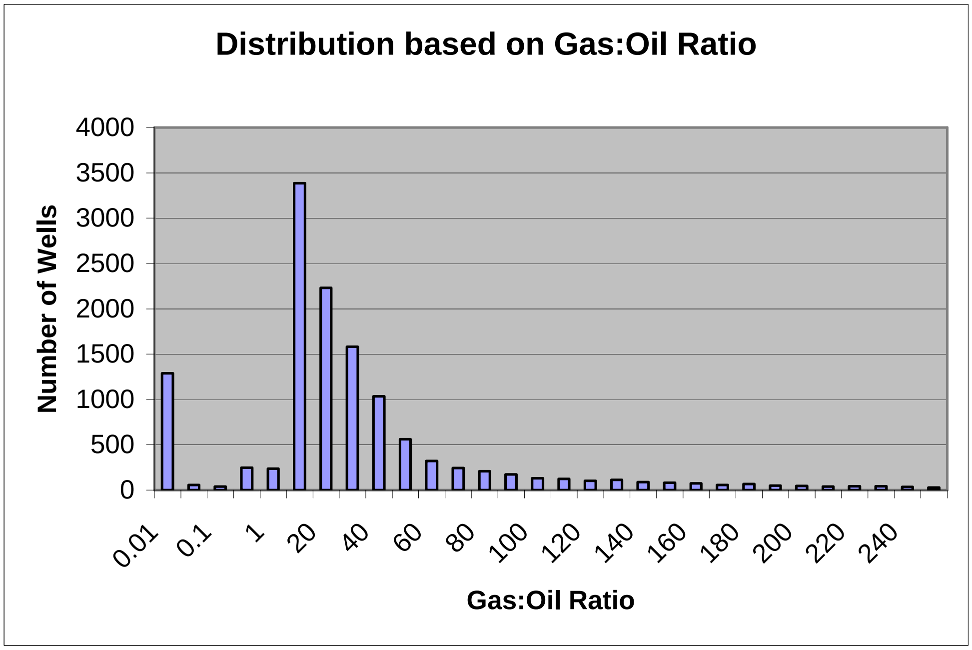


Figure 2-7. Distribution of Colorado wells based on the ratio of gas production to oil production.

There is a clear break in the distribution between wells with a ratio under 0.1 and those with a ratio above 0.1. This break places the great majority of wells into the gas well category. Using a gas:oil ratio of 0.1 to distinguish between oil and gas wells places 1,385 wells in the category of oil wells and 19,847 in the category of gas wells. This may seem an arbitrary division, but it was done based on two considerations. First, this division places the large majority of wells into the category of gas wells. Gas wells have higher emission factors and thus this represents a conservative emissions estimate. Also, the Energy Information Administration estimates over 23 thousand gas wells in the State of Colorado in 2002, which supports this high number of gas wells (EIA, 2005).

The other important division made was between traditional gas wells and coalbed methane gas wells. According to the Wyoming DEQ, the emission factors in Table 2-17 are representative of processes at traditional gas wells, not at coalbed methane wells. The only State for which an identifier was not provided for coalbed methane wells was the State of New Mexico. In the State of New Mexico, coalbed methane wells were identified based on the producing formation reported for the well. The wells producing from one of the formations listed in Table 2-20 were classified as coalbed methane wells. These are the fields indicated for New Mexico in the map of US coalbed methane production produced by the EIA (2004), a section of which is shown in Figure 2-8.

Table 2-20. Coalbed methane producing formations in New Mexico.

Basin Fruitland Coal
Castle Rock Park-Vermejo
Stubblefield Canyon Raton-Vermejo
Van Bremmer Canyon - Vermejo

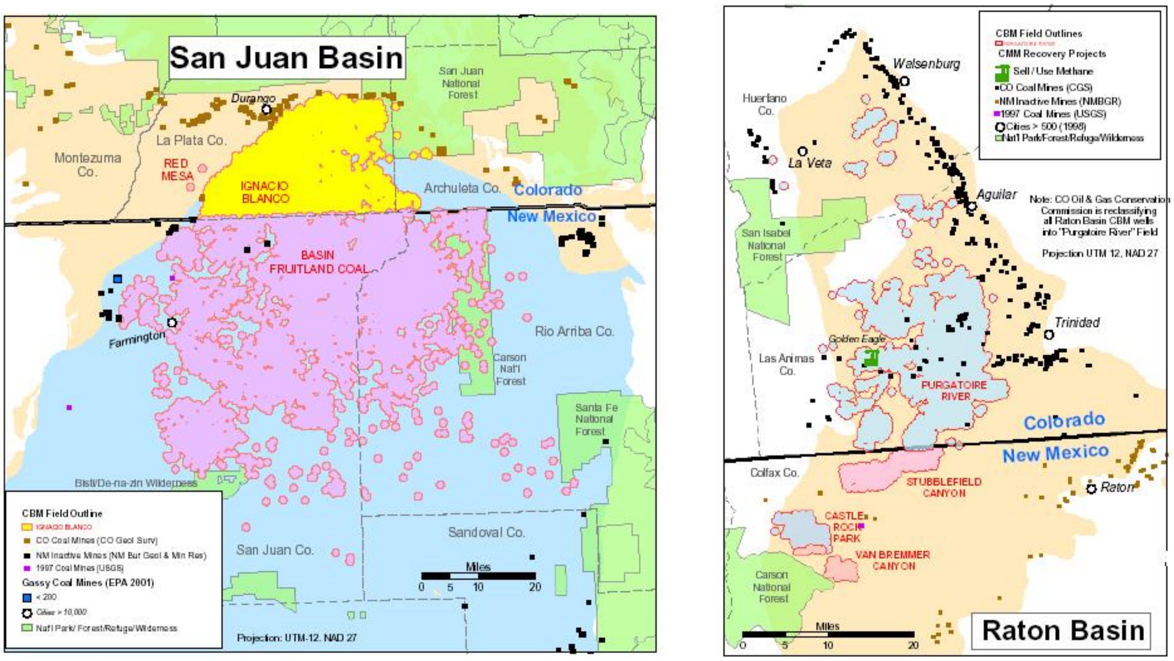


Figure 2-8. Coalbed methane fields in New Mexico.

Having obtained well-specific data from all states, divided those wells into oil and gas wells and then eliminated the coalbed methane wells, there was still one more filtering of the production data required. Because some of the emission factors have units of emissions per well, wells with zero oil and zero gas production and a non-2002 completion date never were removed from consideration. This action would prevent emissions from being estimated at wells where no activity actually occurred in 2002.

Several states reported requiring controls on some of the processes considered in this portion of the inventory. The controls reported and the sources of information are presented in Table 2-21. Both the controls reported by the CDPHE and WY DEQ are included in the emission factors provided by those agencies. The inclusion of these controls in the Wyoming emission factors actually presents a small complication, as those emission factors are used to estimate emissions in all other States, including those States that did not report any controls on condensate tanks or completion emissions. Emissions for completion activities are estimated in all States, except North Dakota and Colorado, using the Wyoming emission factors for completions, despite the inclusion of controls in the WY DEQ emission factors. This has been done because the flaring assumed in the emission factor is not very different from the flaring we would assume based only on safety considerations.

Table 2-21. Controls on sources considered in the VOC and minor NOx source inventory.

State	Condensate Tanks	Completion: Flaring & Venting	Source
Colorado		Included in EF provided	CDPHE, 2005; CDPHE, 2005b
Montana	Flare or vapor recovery required	Flare or vapor recovery required	MT DEQ, 2005
North Dakota	Flare or vapor recovery required	Flare or vapor recovery required	ND DH, 2005
Wyoming	Included in EF provided	Included in EF provided	WY DEQ, 2004b

Wyoming DEQ assumed that condensate tanks with greater than 18.3 barrels per day of condensate production would be controlled with an overall efficiency of 98 percent. For wells with condensate production less than 18.3 barrels per day WY DEQ provided an uncontrolled emission factor (see Table 2-17). To account for the absence of controls on condensate tanks in States, emissions were simply estimated for all wells in those States using the uncontrolled emission factor.

In contrast to those States where no controls were reported for condensate tanks, Montana and North Dakota reported that all condensate tanks are required to achieve the same 98 percent control efficiency reported for the larger wells in Wyoming. For these two States, emissions for all condensate tanks were estimated using the controlled emission factors provided by WY DEQ. Montana and North Dakota environmental agencies also reported that completion emissions must be routed to a flare. No modifications were made to account for the completion controls in North Dakota because flaring completion gases whenever possible is already assumed in the Wyoming emission factor. In the State of Montana, however, it was specified that the control efficiency assumed was 98 percent for an elevated flare (MT DEQ, 2005). The control efficiency for a flaring assumed by WY DEQ was only 50 percent based on observations that flares burn with varying opacity, from 0 to 100 percent, indicating that in many cases a significant portion of the fluid is not combusted (WYDEQ, 2004b). To account for the greater control efficiency reported by Montana DEQ, the Wyoming emission factors were adjusted for use in Montana.

Based on a typical well completion log, the Wyoming DEQ assumed that 5.0 MMSCF of gas are flared or vented during 10 days of completion activity. Using the same characteristics of the completion gas as were used by Wyoming DEQ and substituting the Montana DEQ assumption of 98 percent control, it was possible to calculate new emission factors for Montana using AP-42 emission factors for a flare. The details of this calculation, including the assumed gas characteristics are shown in Calculation 8.

Calculation 8. Calculation of completion emission factors for Montana

Assumptions adopted from Wyoming DEQ:

- 5.0 MMCF gas flared or venting daily for 10 days of completion activities
- VOC and HAP weight percent of gas is 9.43
- Gas molecular weight of 18.456 lb/lb-mol
- 1000 Btu/SCF

Information provided by Montana DEQ:

- 100 percent of completion gases must be flared
- flare has a 98 percent destruction efficiency

AP-42 emission factors:

- 0.14 lb NOx/MMBtu
- 0.035 lb CO/MMBtu

VOC Emission Factor

EF = V x (10^6 SCF/MMCF) x F x MW x 1/D x (1 - e) x (ton/2000 lb) x W

with:

EF = VOC emission factor (ton VOC per completion)
V = the volume of gas vented or flared per completion (MMCF per completion)
F = the fraction of gas sent to the flare (1.0 for Montana)
MW = molecular weight of gas (lb/lb-mol)
D = conversion factor, 379 SCF/lb-mol
e = flare destruction efficiency (0.98 for Montana)
W = fraction of gas that is VOC

EF = 50 MMCF x (10^6 SCF/MMCF) x 1 x 18.46 lb/lb-mol x 1/(379 SCF/lb-mol) x (1-0.98) x (ton/2000 lb) x 0.0943
EF = 2.3 tons VOC per completion

NOx Emission Factor

EF = V x (10^6 SCF/MMCF) x F x H x (MMBtu/10^6 Btu) x A x (ton/2000 lb)

with:

EF = NOx emission factor (ton NOx per completion)
V = the volume of gas vented or flared per completion (MMCF per completion)
F = the fraction of gas sent to the flare (1.0 for Montana)
H = the heating value of the gas (1000 Btu/SCF)
A = AP-42 emission factor for a flare (0.14 lb NOx/MMBtu)

EF = 50 MMCF x (10^6 SCF/MMCF) x 1.0 x 1000 Btu/SCF x (MMBtu/10^6 Btu) x 0.14 lb NOx/MMBtu x (ton/2000 lb)
EF = 3.5 ton NOx per completion

A summary of the final gas well emission factors used is presented in Table 2-22. The final oil well emission factors used are those presented in Table 2-17. Having determined the control-adjusted Montana completion emission factors, and the procedure for incorporating condensate controls into emissions calculations, we proceeded to estimate emissions. Emission factors, adjusted as described for controls, were combined with the well data to estimate emissions following the general procedure shown in Calculation 9. For completion emissions in the State of Colorado, the emission factors provided by CDPHE were used. CDPHE personnel indicated that the completion emission factor was based on information for one area of the State and may not be applicable to the entire State (CDPHE, 2005). However, because no additional factor was provided for the rest of the State, this same emission factor has been used for all of Colorado.

Table 2-22. Summary of control-adjusted gas well emission factors for VOC and minor NOx sources.

	Gas Well Process				
State	**Condensate Tanks (lb VOC per year/BPD)**	**Dehydrator (lbs VOC per year/MCFD)**	**Heater (lbs NOx per year/well)**	**Completion (tons per completion)**	**Pneumatic Devices (tons VOC per year/well)**
Alaska	NA	NA		VOC = 86 NOx = 1.75	
Arizona	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Colorado	NA	NA	1,752	VOC = 16.7 NOx = 0.85	0.2
Montana	65	NA	1,752	VOC = 2.3 NOx = 3.5	0.2
Nevada	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
New Mexico	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
North Dakota	65	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Oregon	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
South Dakota	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Utah	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Wyoming	3,271 (uncontrolled) 65 (controlled)	27,485	1,752	VOC = 86 NOx = 1.75	0.2

Calculation 9 presents a general outline of how emissions were estimated for the VOC and minor NOx processes. For detailed sample calculations for each of these processes, refer to Appendix B. A summary of the emissions estimated for VOC and minor NOx processes is presented in Table 2-23.

Calculation 9. Calculation of wellhead emissions for individual wells

Gas Well

$$E = SUM_i(P_g \times EF_{g,i}) + SUM_j(Pc \times EF_{c,j}) + SUM(EF_w)$$

where:

E = The 2002 emission
P_g = 2002 gas production
$EF_{g,i}$ = Emission factor for gas process i
P_c = 2002 condensate production
$EF_{c,j}$ = Emission factor for condensate process j
EF_w = Per well emission factor

Oil Well

$$E = SUM_i(P_o \times EF_{g,i}) + SUM(EF_w)$$

where:

E = The 2002 emission
P_o = 2002 oil production
$EF_{o,i}$ = Emission factor for oil process i
EF_w = Per well emission factor

Table 2-23. State total emissions for VOC and minor NOx sources.

State	VOC	NOx
Alaska[1]	430	9
Arizona	46	9
Colorado[2]	25,426	15,953
Idaho	0	0
Montana[3]	5,439	4,721
Nevada	129	5
New Mexico	168,091	13,967
North Dakota	7,740	176
Oregon	34	12
South Dakota	288	47
Utah	35,896	2,158
Washington	0	0
Wyoming	118,828	6,510

[1] Emissions in Alaska estimated only for completion emissions.
[2] Emissions in Colorado not estimated for condensate tanks or glycol dehydrators.
[3] Emissions in Montana not estimated for glycol dehydrators.

Several modifications are represented in this summary table that have not yet been mentioned. Emissions for condensate tanks and glycol dehydrators are not included for the State of Colorado. In Colorado, those sources are expected to be included in the point source inventory due to the low inventory threshold (CDPHE, 2005b). Nor are emissions included for any process, except completion activities, in the State of Alaska. Again, emissions from the other VOC and minor NOx sources are expected to be included in the State's point source inventory; in this case because wellhead equipment is permitted under the umbrella of larger facilities (AK OGCC, 2005b; AK DEC, 2005b). Emissions have not been estimate for glycol dehydrators in the State of Montana because it was reported that no wellhead dehydrators have been installed in Montana (MT DEQ, 2005).

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Appendix A

Wyoming Emission Factor Documentation

Gas Wells – Completion Emissions from Flaring and Venting

Standardized statewide factors for VOC and HAP emissions associated with flaring and venting activities during gas well completions were created using a weighted average statewide produced gas composition. The averaged analysis indicates VOC and HAP weight percents of 9.43% and 0.33%, respectively

A typical well completion log indicated 5.0 MMCFD of gas are flared and/or vented during 10-days of completion activities. This is the only well completion log available to the Division and is representative of gas well completions in the Pinedale, Wyoming area, where the majority of gas well completions during 2002 occurred.

During well completions, fluids routed to the flares burn when the entrained liquid volumes are low enough. Sometimes the flares are burning basically pure gas, while other times the flares don't or won't ignite when liquid volumes are excessive. Since typical volumes of gas and liquid routed to a completion flare are not known, 50% of the time for each situation is assumed.

During flaring of completion gas, different opacity levels have been observed, ranging from 0 to 100%. This indicates completion fluids are not 100% combusted. Sometimes well flares smoke excessively and sometimes they burn clean, depending on the amount of liquids entrained in the flared vapors. To account for this, 50% destruction efficiency of flares for VOCs and HAPs are assumed.

Emissions associated with gas venting are calculated as follows:

(5 MMCF/day) × (18.4565 lb/lb-mol) × (lb-mol/379 scf) × (10^6 scf/MMCF) × (ton/2000 lb)
= 121.7447 tons of total gas flared or vented per day per completion

121.7447 tons of gas per day × 10 days = 1217.4472 tons of gas per completion

1217.4472 total tons × 0.0943 wt% VOC = 114.8053 total tons VOC

50% of 114.8053 tons VOC are vented = 57.4027 tons VOC vented per completion

50% of 114.8053 tons VOC are flared w/ 50% destruction efficiency
= 28.7013 tons VOC from incomplete combustion per completion

Total VOC from flaring/venting = 86.0 tons per well completion

1217.4472 total tons × 0.0033 wt% HAP = 4.0176 total tons HAP

50% of 4.0176 tons HAP are vented = 2.0088 tons HAP vented per completion

50% of 4.0176 tons HAP are flared w/ 50% destruction efficiency
= 1.0044 tons HAP from incomplete combustion per completion

Gas Wells – Completion Emissions from Flaring and Venting cont'd

Total HAP from flaring/venting = 3.0 tons per well completion

0.6087 total tons Benzene @ 50% vented/50% flared = **0.5 tons Benzene per well/completion**
1.0957 total tons Toluene @ 50% vented/50% flared = **0.7 tons Toluene per well/compl**etion
0.3652 total tons Xylene @ 50% vented/50% flared = **0.8 tons Xylene per well/completion**
1.9479 total tons n-C^6 @ 50% vented/50% flared = **1.3 tons n-C^6 per well/completion**
undetectable e-Benzene

For NO_X and CO emissions from flaring, AP-42 flare emission factors were used as follows:

(5.0 MMCF/day) × (0.14 lb NO_X/MMBtu) × (1000 Btu/SCF) × (10^6 SCF/MMCF) × (MMBtu/10^6 Btu) × (ton/2000 lb) = 0.35 tons NO_X per day.

Using the same calculate with 0.035 lb CO/MMCF = 0.0875 tons CO per day

Assuming gas wells are flared 50% of the time during 10 days of completion operations flaring emissions are:

1.75 tons NO_X & 0.44 tons CO per gas well completion

VOC and HAP emissions from pneumatic devices at gas and oil well facilities

The average pneumatic pump uses and emits approximately 5.0 SCF/hr. These pumps are to inject methanol into flowlines and equipment at oil and gas well facilities. Most gas wells have two associated pneumatic injection pumps. Most oil wells have one associated pneumatic pump. Each type of well has various other pneumatic devices.

VOC and HAP emission from pneumatic pumps are calculated using the statewide average weighted gas composition, 5.0 SCF/hr gas usage, two pumps per gas well and one pump per oil well, as follows:

(5 SCF/hr) × (18.4565 lb/lb-mol) × (lb-mol/379 SCF) × (8760 hr/yr) (ton/2000 lb)
= 1.07 tons gas used per year per pump

1.07 tons × 0.0943 wt% VOC = 0.1 tons VOC per year/pump

1.07 tons × 0.0033 wt% HAP = 0.004 tons HAP per year/pump

For each gas well pneumatic emissions are 0.2 tons VOC/yr/well and 0.008 tons HAP/yr/well

For each oil well pneumatic emissions are 0.1 tons VOC/yr/well and 0.004 tons HAP/yr/well

VOC and HAP emissions from other pneumatic devices at each oil and gas well are typically less than 1.0 TPY VOC and less than 0.1 TPY HAP.

Gas Wells – Flashing & Standing/Working/Breathing VOC Emissions

Standardized statewide emission factors for storage tank emissions were created by calculating the average compositions of condensate for each formation for which analyses were available. These averages were used to formulate a weighted average for condensate composition across the state, based on production per formation. The weighted average was used with E&P Tanks modeling software to calculate emission factors in tons per year (TPY) per barrel per day (BPD) of condensate production.

The calculations yielded emissions of 3,271.0 pounds per year (1.64 TPY) of VOCs per BPD and 116.0 pounds per year (0.06 TPY) of HAPs per BPD uncontrolled. For wells that produce above 18.3 BPD of condensate controls would be installed, since the VOC emission would be above the 30.0 TPY threshold used in 2002. The emission factors would then be 65.74 pounds per year (0.03 TPY) of VOCs per BPD and 2.32 pounds per year (0.001 TPY) of HAPs per BPD controlled with 98% efficiency.

Uncontrolled	**Controlled**
Benzene = 31.4 lb per yr/BPD	Benzene = 0.63 lb per yr/BPD
Toluene = 0.8 lb per yr/BPD	Toluene = 0.02 lb per yr/BPD
Ethyl benzene = 2.6 lb per yr/BPD	Ethyl benzene = 0.05 lb per yr/BPD
Xylenes = 1.8 lb per yr/BPD	Xylenes = 0.04 lb per yr/BPD
n-Hexane = 7.8 lb per yr/BPD	n-Hexane = 0.16 lb per yr/BPD

Gas Wells – Dehydration Unit VOC & HAP Emissions

Standardized statewide emission factors for dehydration unit emissions were created by calculating the average compositions of wet gas for each formation for which analyses were available. These averages were used to formulate a weighted average for gas composition across the state, based on production per formation. The weighted average was then used with GRI GlyCalc modeling software to calculate emission factors based on one million standard cubic foot of gas per day (MSCFD) at 0.425 gpm or 25.0 spm for a Kimray 4015 glycol pump. 25.0 spm is an observed average pump rate and the Kimray 4015 model is the most widely used.

The calculations yielded emissions of 27,485.6 pounds per year (13.74 TPY) of VOCs per 10^6 cubic feet per day (MMCFD) and 13,695.6 pounds per year (6.85 TPY) of HAPs per MMCFD.

Benzene = 3,019.0 lb per yr/MMCFD
Toluene = 6,944.2 lb per yr/MMCFD
Ethyl benzene = 288.8 lb per yr/MMCFD
Xylenes = 3,054.8 lb per yr/MMCFD
n-Hexane = 361.0 lb per yr/MMCFD

Gas Wells – Heater Emissions

For an average gas well site, approximately 2.0 MMBtu/hr are used in all of the different heaters and burners. The average heat content of the fuel used in these heaters is estimated at 1000 Btu/scf. This activity results in 1,752.0 pounds per year (0.88 TPY) of NOx and 367.92 pounds per year (0.18 TPY) of CO for each gas well installation. These were calculated using AP-42 emission factors for fuel boilers and heaters, 100 lb/mmcf for NOx and 21 lb/mmcf for CO.

Oil Wells – Flashing & Standing/Working/Breathing VOC Emissions

Statewide standardized emission factors for storage tank emissions were formulated using the geographical database built into E&P Tanks emissions modeling software. The data gathered for sales oil with an API Gravity of 30.0 and Reid Vapor Pressure of 2.7 psia was selected as it most closely approximates the majority of Wyoming crude oil. The resulting factors in pounds of emissions per year per BPD oil production at individual wells:

VOCs = 160.0 lb per yr/BPD
HAPs = 2.66 lb per yr/BPD
Benzene = 0.014 lb per yr/BPD
Toluene = 0.018 lb per yr/BPD
Ethyl Benzene = 0.004 lb per yr/BPD
Xylenes = 0.034 lb per yr/BPD
n-Hexane = 2.598 lb per yr/BPD

Oil Wells – Heater Emissions

In Wyoming, most oil wells are produced to a central battery where various heated vessels are used for separation of crude and water. An average throughput of 2000 barrels per day at a facility using 4.0 MMBtu/hr total heat input was used along with AP-42 emission factors for fuel boilers and heaters to estimate 0.005 pounds per year of NO_X per BPD and 0.001 pounds per yr of CO per BPD of oil production at each individual oil well [later corrected units to 0.005 pounds per year of NOx per barrel and 0.001 pounds per year of CO per barrel].

Appendix B

Sample Calculations for the VOC and Minor NOx Processes

Sample Calculation for Gas Well

Well Name = 476
Well Type = Gas
Field Name = Five Mile
County = Big Horn
2002 Gas Production (GP) = 193,559 1000CF
2002 Condensate Production (CP) = 2,968 barrels
Completion Date = 6/25/2002

Calculate approximate number of operational days per year
Number of days June - December = 214 well days per year (wdpy)

Flashing & Standing/Working/Breathing Emissions
Will there be controls on flashing & standing/working/breathing?
CP / wdpy <= 18.3
2,968 barrels / 214 wdpy <= 18.3
13.9 <= 18.3 therefore there will be no controls
VOC EF = 3,271 lbs/yr per BPD CP
Benzene EF = 31.4 lbs/yr per BPD CP

Annual VOC = CP / wdpy * VOC EF / 2000 lb/ton * wdpy / total dpy
Annual VOC = 2,968 barrels / 214 wdpy * 3,271 lbs/yr per BPD CP / 2000 lb/ton * 214 wdpy / 365 dpy
Annual VOC = 13.9 bpd * 3,271 lbs/yr per BPD CP / 2000 lb/ton * .586
Annual VOC = 13.3 tons

Annual Benzene = CP / wdpy * Benzene EF / 2000 lb/ton * wdpy / total dpy
Annual Benzene = 13.9 bpd * 31.4 lbs/yr per BPD CP / 2000 lb/ton * .586
Annual Benzene = .13 tons

Dehydration Unit Emissions
VOC EF = 27,485.6 lbs per year / MCFD
Annual VOC = VOC EF * GP / 1000 MCF/1000CF / 214 wdpy / 2000 lb/ton * 214 wdpy / 365 dpy
Annual VOC = 27,485.6 lbs per year / MCFD * 193.6MCF / 214 wdpy / 2000 lb/ton * .586
Annual VOC = 7.3 tons

Heater Emissions
NOx EF = 1,752 lbs / year - well
Annual NOx = NOX EF * Number of Wells / 2000 lb/ton * wdpy / dpy
Annual NOx = 1,752 lbs / year-well * 1 well / 2000 lb/ton * .586
Annual NOx = .51 tons

Pneumatic Devices
VOC EF = .2 tons / year-well
Annual VOC = VOC EF * Number of Wells * wdpy / dpy
Annual VOC = .2 tons / year-well * 1 well * .586
Annual VOC = .12 tons

Completion Flaring and Venting
VOC EF = 86 tons / completion
Annual VOC = completions * VOC EF
Annual VOC = 1 completion * 86 tons / completion
Annual VOC = 86 tons

These sample calculations only present the calculation for one pollutant for each process. The calculations for other pollutants within the same process were identical, with the exception of the emission factor.

Sample Calculation for Oil Well

Well Name = 483
Well Type = Oil
Field Name = Torchlight
County = Big Horn
2002 Oil Production (OP) = 8,758 barrels
Completion Date = 2/4/2002

Calculate approximate number of operational days per year
Number of days February - December = 334 well days per year (wdpy)

Flashing & Standing/Working/Breathing Emissions
VOC EF = 160 lb/year per BPD OP
Annual VOC = VOC EF * OP / wdpy / 2000 lb/ton * wdpy / dpy
Annual VOC = 160 lb/year per BPD OP * 8,758 barrels / 334 wdpy / 2000 lb/ton * 334 wdpy / 365 dpy
Annual VOC = 160 lb/year per BPD OP * 26.2 BPD / 2000 lb/ton * .915
Annual VOC = 1.92 tons

Heater
NOx EF = 0.005 lb/yr per BPD OP
Annual NOx = NOx EF * OP / wdpy / 2000 lb/ton * wdpy / dpy
Annual NOx = 0.005 lb/yr per BPD OP * 26.2 BPD / 2000 lb/ton * .915
Annual NOx = 0.00006 tons

Pneumatic Devices
VOC EF = 0.10 tons/yr per well
Annual VOC = VOC EF * Number of Wells * wdpy / dpy
Annual VOC = 0.10 tons/yr per well * 1 well * .915
Annual VOC = 0.092 tons

Appendix C

Nonroad Diesel Fuel Sulfur Levels

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
02013	0.075	08071	0.050	30013	0.240
02016	0.075	08073	0.050	30015	0.240
02020	0.119	08075	0.050	30017	0.240
02050	0.075	08077	0.050	30019	0.240
02060	0.075	08079	0.050	30021	0.240
02068	0.075	08081	0.050	30023	0.240
02070	0.075	08083	0.050	30025	0.240
02090	0.119	08085	0.050	30027	0.240
02100	0.035	08087	0.050	30029	0.240
02110	0.035	08089	0.050	30031	0.240
02122	0.119	08091	0.050	30033	0.240
02130	0.035	08093	0.050	30035	0.240
02150	0.075	08095	0.050	30037	0.240
02164	0.075	08097	0.050	30039	0.240
02170	0.119	08099	0.050	30041	0.240
02180	0.075	08101	0.050	30043	0.240
02185	0.075	08103	0.050	30045	0.240
02188	0.075	08105	0.050	30047	0.240
02201	0.035	08107	0.050	30049	0.240
02220	0.035	08109	0.050	30051	0.240
02232	0.035	08111	0.050	30053	0.240
02240	0.119	08113	0.050	30055	0.240
02261	0.119	08115	0.050	30057	0.240
02270	0.075	08117	0.050	30059	0.240
02280	0.035	08119	0.050	30061	0.240
02282	0.075	08121	0.050	30063	0.240
02290	0.075	08123	0.050	30065	0.240
04001	0.240	08125	0.050	30067	0.240
04003	0.240	16001	0.330	30069	0.240
04005	0.340	16003	0.330	30071	0.240
04007	0.340	16005	0.330	30073	0.240
04009	0.240	16007	0.330	30075	0.240
04011	0.240	16009	0.330	30077	0.240
04012	0.340	16011	0.330	30079	0.240
04013	0.036	16013	0.330	30081	0.240
04015	0.340	16015	0.330	30083	0.240
04017	0.240	16017	0.330	30085	0.240
04019	0.340	16019	0.330	30087	0.240
04021	0.340	16021	0.330	30089	0.240
04023	0.240	16023	0.330	30091	0.240
04025	0.340	16025	0.330	30093	0.240
04027	0.340	16027	0.330	30095	0.240
08001	0.050	16029	0.330	30097	0.240
08003	0.050	16031	0.330	30099	0.240
08005	0.050	16033	0.330	30101	0.240
08007	0.050	16035	0.330	30103	0.240

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
08009	0.050	16037	0.330	30105	0.240
08011	0.050	16039	0.330	30107	0.240
08013	0.050	16041	0.330	30109	0.240
08014	0.050	16043	0.330	30111	0.240
08015	0.050	16045	0.330	30113	0.240
08017	0.050	16047	0.330	32001	0.050
08019	0.050	16049	0.330	32003	0.025
08021	0.050	16051	0.330	32005	0.050
08023	0.050	16053	0.330	32007	0.050
08025	0.050	16055	0.330	32009	0.050
08027	0.050	16057	0.330	32011	0.050
08029	0.050	16059	0.330	32013	0.050
08031	0.050	16061	0.330	32015	0.050
08033	0.050	16063	0.330	32017	0.025
08035	0.050	16065	0.330	32019	0.050
08037	0.050	16067	0.330	32021	0.050
08039	0.050	16069	0.330	32023	0.025
08041	0.050	16071	0.330	32027	0.050
08043	0.050	16073	0.330	32029	0.050
08045	0.050	16075	0.330	32031	0.050
08047	0.050	16077	0.330	32033	0.050
08049	0.050	16079	0.330	32510	0.050
08051	0.050	16081	0.330	35001	0.240
08053	0.050	16083	0.330	35003	0.240
08055	0.050	16085	0.330	35005	0.240
08057	0.050	16087	0.330	35006	0.240
08059	0.050	30001	0.240	35007	0.240
08061	0.050	30003	0.240	35009	0.240
08063	0.050	30005	0.240	35011	0.240
08065	0.050	30007	0.240	35013	0.240
08067	0.050	30009	0.240	35015	0.240
08069	0.050	30011	0.240	35017	0.240

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
35019	0.240	41007	0.340	46095	0.371
35021	0.240	41009	0.340	46097	0.371
35023	0.240	41011	0.340	46099	0.371
35025	0.240	41013	0.340	46101	0.371
35027	0.240	41015	0.340	46103	0.240
35028	0.240	41017	0.340	46105	0.240
35029	0.240	41019	0.340	46107	0.371
35031	0.240	41021	0.340	46109	0.371
35033	0.240	41023	0.340	46111	0.371
35035	0.240	41025	0.340	46113	0.240
35037	0.240	41027	0.340	46115	0.371
35039	0.240	41029	0.340	46117	0.371
35041	0.240	41031	0.340	46119	0.371
35043	0.240	41033	0.340	46121	0.371
35045	0.240	41035	0.340	46123	0.371
35047	0.240	41037	0.340	46125	0.371
35049	0.240	41039	0.340	46127	0.371
35051	0.240	41041	0.340	46129	0.371
35053	0.240	41043	0.340	46135	0.371
35055	0.240	41045	0.340	46137	0.371
35057	0.240	41047	0.340	49001	0.340
35059	0.240	41049	0.340	49003	0.240
35061	0.240	41051	0.340	49005	0.240
38001	0.240	41053	0.340	49007	0.240
38003	0.371	41055	0.340	49009	0.240
38005	0.371	41057	0.340	49011	0.240
38007	0.240	41059	0.340	49013	0.240
38009	0.371	41061	0.340	49015	0.240
38011	0.240	41063	0.340	49017	0.340
38013	0.240	41065	0.340	49019	0.240
38015	0.371	41067	0.340	49021	0.340
38017	0.371	41069	0.340	49023	0.240
38019	0.371	41071	0.340	49025	0.340
38021	0.371	46003	0.371	49027	0.240
38023	0.240	46005	0.371	49029	0.240
38025	0.240	46007	0.371	49031	0.340
38027	0.371	46009	0.371	49033	0.240
38029	0.371	46011	0.371	49035	0.240
38031	0.371	46013	0.371	49037	0.240
38033	0.240	46015	0.371	49039	0.240
38035	0.371	46017	0.371	49041	0.240
38037	0.371	46019	0.240	49043	0.240
38039	0.371	46021	0.371	49045	0.240
38041	0.240	46023	0.371	49047	0.240
38043	0.371	46025	0.371	49049	0.240
38045	0.371	46027	0.371	49051	0.240

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
38047	0.371	46029	0.371	49053	0.340
38049	0.371	46031	0.371	49055	0.240
38051	0.371	46033	0.240	49057	0.240
38053	0.240	46035	0.371	53001	0.340
38055	0.371	46037	0.371	53003	0.340
38057	0.371	46039	0.371	53005	0.340
38059	0.371	46041	0.371	53007	0.340
38061	0.240	46043	0.371	53009	0.340
38063	0.371	46045	0.371	53011	0.340
38065	0.371	46047	0.240	53013	0.340
38067	0.371	46049	0.371	53015	0.340
38069	0.371	46051	0.371	53017	0.340
38071	0.371	46053	0.371	53019	0.340
38073	0.371	46055	0.371	53021	0.340
38075	0.371	46057	0.371	53023	0.340
38077	0.371	46059	0.371	53025	0.340
38079	0.371	46061	0.371	53027	0.340
38081	0.371	46063	0.240	53029	0.340
38083	0.371	46065	0.371	53031	0.340
38085	0.371	46067	0.371	53033	0.340
38087	0.240	46069	0.371	53035	0.340
38089	0.240	46071	0.371	53037	0.340
38091	0.371	46073	0.371	53039	0.340
38093	0.371	46075	0.371	53041	0.340
38095	0.371	46077	0.371	53043	0.340
38097	0.371	46079	0.371	53045	0.340
38099	0.371	46081	0.240	53047	0.340
38101	0.371	46083	0.371	53049	0.340
38103	0.371	46085	0.371	53051	0.340
38105	0.240	46087	0.371	53053	0.340
41001	0.340	46089	0.371	53055	0.340
41003	0.340	46091	0.371	53057	0.340
41005	0.340	46093	0.240	53059	0.340

County FIPs	Fuel Diesel Sulfur (%)
53061	0.340
53063	0.340
53065	0.340
53067	0.340
53069	0.340
53071	0.340
53073	0.340
53075	0.340
53077	0.340
56001	0.270
56003	0.270
56005	0.270
56007	0.270
56009	0.270
56011	0.270
56013	0.270
56015	0.270
56017	0.270
56019	0.270
56021	0.270
56023	0.270
56025	0.270
56027	0.270
56029	0.270
56031	0.270
56033	0.270
56035	0.270
56037	0.270
56039	0.270
56041	0.270
56043	0.270
56045	0.270