EXHIBIT 3

Russell, J. and A. Pollack, "Oil and Gas Emission Inventories for the Western States," Final Report prepared for Western Governor's Association (December 27, 2005)

Final Report

OIL AND GAS EMISSION INVENTORIES FOR THE WESTERN STATES

Prepared for

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PREFACE

Regulatory Framework for Tribal Visibility Implementation Plans

The Regional Haze Rule explicitly recognizes the authority of tribes to implement the provisions of the Rule, in accordance with principles of Federal Indian law, and as provided by the Clean Air Act (CAA) §301(d) and the Tribal Authority Rule (TAR) (40 CFR §§49.1– .11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.

2. Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a Tribal Implementation Plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.

3. The Regional Haze Rule expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12).

4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003; rather they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).

5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a Federal Implementation Plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government to government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg.7263-64).

The amount of modification necessary will vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribal Participation in the WRAP

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the state, federal, and private stakeholder interests in approving this report as a consensus document.

An adjunct study of oil and gas emissions point and area source emissions was conducted by ENVIRON and ERG. Oil and gas emissions for four tribes were inventoried: Wind River Reservation, Ute Mountain Ute Tribe, Navajo Nation, and Jicarilla Apache Nation. Emissions sources for the Jicarilla Apache Nation were inventoried, but they elected to not formally participate in the project. The final project report, *Point Source and Oil and Gas Area Source Emission Inventories on Native American Reservations and Tribal Lands* (ERG/ENVIRON, 2005), does not include Jicarilla Apache data.

1. INTRODUCTION

The oil and gas production industry considered in this study includes a large number of processes and equipment types that stretch from the wellhead to fuel distribution networks. Many of these processes emit significant quantities of nitrous oxides (NOx), volatile organic compounds (VOC) and other pollutants. Past emission inventories have estimated emissions from specific pieces of equipment, for limited geographic areas and for other segments of the industry. The largest oil and gas production facilities, gas plants and major compressor stations, have been previously inventoried as stationary sources. All states in the western region had previously compiled emission inventories for the year 2002 that included the major "point" emission sources in the oil and gas production industry. However, what was included in these emission inventories varied from state to state, depending on the permitting and/or reporting thresholds.

Oil and gas production facilities that are geographically distributed and have lesser emissions than the point source threshold are considered area sources. Prior to this study, there had not been a comprehensive emission inventory of oil and gas production operations in the western region that covered both point and area sources. Nor had there been a methodology developed to produce an inventory of this scope. The objective of the present study has thus been to develop and implement a uniform procedure for estimating area source emissions from oil and gas production operations across the western region. The emphasis of this study was placed on estimating emissions of pollutants with the potential to impair visibility near Class I areas in the west, in particular NOx emissions.

As this was the first effort to develop a regionally consistent emission inventory for oil and gas area sources, and resources were limited, this inventory is neither comprehensive nor as accurate as it might be with more resources. The focus was on the larger sources of NOx emissions; NOx and VOC emissions from minor wellhead processes for which emission factors were available were also estimated. This inventory and the methodology used should be considered as a first step toward a better understanding of oil and gas emissions, and the basis for further work to improve the estimates.

In developing the emission estimation methodology, considerable resources were devoted to incorporating the insights and guidance of a variety of stakeholders, as well as integrating the point source emissions estimates developed in previous inventory efforts. The work plans that guided this project were developed with substantial feedback from members of the WRAP Stationary Sources Joint Forum (SSJF) Oil and Gas Work Group.

The 2002 oil and gas point source emissions have been adopted from the state inventories (ERG, 2005a). The level of coverage in those inventories was evaluated and the point source emissions have been reconciled with emissions estimated using the newly developed area source inventory methodology.

Oil and gas point source emission inventories include location parameters. For the oil and gas area source emissions estimated in this project, a new spatial allocation scheme was developed to facilitate the integration of these emissions sources into the WRAP regional haze modeling. New spatial surrogates were developed for each of the non-point oil and gas emission sources addressed by this inventory. These surrogates, which are based on the geographic locations of oil and gas production, will enable the appropriate spatial distribution of emissions from oil and gas production operations in the air quality modeling.

The final task of this project was to formulate and implement a procedure to project the emissions from oil and gas production operations in 2018. For the WRAP 2018 base case modeling, only those emission control strategies that have already been adopted are considered. Once again, the work plan that guided the development of the projection method was developed in collaboration with the stakeholders represented in the SSJF Oil And Gas Work Group. Ultimately, oil and gas production forecasts were drawn from several sources and combined with the emissions estimates produced for the 2002 inventory and information on future controls to arrive at the 2018 inventory. Oil and gas point source projections are described in a separate report (ERG, 2005b).

This report describes the procedures developed in each task of this project and the results that have been obtained. Section 2 presents the methodology developed to create a comprehensive oil and gas emissions inventory for the western region and summarizes the emission inventory that was prepared for the year 2002. Section 3 then details the process used to create the spatial allocation surrogates that will appropriately assign oil and gas emissions to the locations where they occur. Section 4 describes the data sources and methods that have been used to project emissions in the year 2018, and provides the resulting emissions estimates.

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 do not include emissions classified as falling under tribal jurisdiction. ENVIRON has prepared separate emissions estimates of tribal oil and gas emissions for four tribes. Those emissions estimates are reconciled with the emissions reported here, and separate documentation of tribal emissions has been prepared (ERG/ENVIRON, 2005).

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 2-1a presents a summary of NOx emissions from oil and gas area sources in the WRAP States. Table 2-1b presents a similar summary of VOC emissions. The area source emissions are distinguished by source category, except in California where only the total NOx emission from the ARB inventory is given. The point source emissions included in Tables 2-1a and 2-1b include several types of oil and gas facilities that are listed under SIC codes 13**, 492* or 4612 (ERG, 2005a). In most states, the major contributors of point source oil and gas emissions are natural gas transmission stations and natural gas processing plants. Crude oil pump stations and large storage sites also make a significant contribution in some states. Notably, the point source inventory methods in the State of Colorado and the State of Alaska are such that the majority of oil and gas emissions sources are included in the point source inventory.

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

State	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source Total	Point Source Total	TOTAL
Alaska		877	9		886	45,822	46,708
Arizona						2,735	2,735
California					8,070	16,707	24,777
Colorado		5,734	15,924	1,489	23,147	25,955	49,102
Idaho						2,590	2,590
Montana	2,027	1,044	4,721		7,792	4,275	12,067
Nevada	33	24	5		62	83	145
New Mexico	40,095	6,645	13,482	225	60,446	57,173	117,619
North Dakota	2,920	1,536	176		4,631	4,739	9,369
Oregon	73	-	12		85	1,182	1,267
South Dakota	284	36	47		367	323	690
Utah	2,371	676	2,143		5,190	3,311	8,500
Washington						1,281	1,281
Wyoming	7,025	4,964	6,283	1,428	19,699	15,015	34,715
Total	**54,828**	**21,536**	**42,800**	**3,141**	**130,376**	**181,191**	**311,566**

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 2-1b. 2002 State total VOC emissions (tons) from oil and gas area sources.

State	Oil Well, Tanks	Oil Well, Pneumatic Devices	Gas Well, Pneumatic Devices	Gas Well, Dehydrators	Gas Well, Completion - Flaring and Venting	Condensate Tanks - Uncontrolled	Condensate Tanks - Controlled	Area Source Total	Point Source Total	TOTAL
Alaska					430			430	2,310	2,740
Arizona									233	233
California								18,712	7,101	25,813
Colorado	785	137	3,388		21,075			25,386	63,960	89,346
Idaho									78	78
Montana	3,721	357	912		448	-	1	5,439	687	6,126
Nevada	121	7	1	0	-	-	-	129	23	152
New Mexico	10,671	1,484	2,893	40,509	33,884	77,333	-	166,773	11,527	178,300
North Dakota	6,572	329	22	601	172	-	43	7,740	187	7,926
Oregon	-	-	3	32	-	-	-	34	40	74
South Dakota	246	12	10	19	-	-	-	288	26	314
Utah	1,689	128	384	5,753	21,758	5,045	-	34,757	852	35,609
Washington									64	64
Wyoming	9,320	969	1,236	44,721	37,410	21,036	334	115,027	6,283	121,311
Total	**33,127**	**3,424**	**8,849**	**91,636**	**115,176**	**103,414**	**378**	**374,715**	**93,371**	**468,087**

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 59 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 182, 98 and 157 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 NOx emissions in the 2002 inventory as a result of this inventory effort.

	WRAP Oil and Gas Inventory			Oil and Gas in Previous Inventory			Change in Oil and Gas Emissions	
State/Tribe	Area	Point	Total	Area	Point	Total	Total	Percent
Alaska	886	45,822	46,708		45,822	45,822	886	2%
Arizona		2,735	2,735		2,735	2,735	-	0%
California*	8,070	16,707	24,777	8,070	16,707	24,777	-	0%
Colorado	23,147	25,955	49,102		25,955	25,955	23,147	89%
Idaho		2,590	2,590		2,590	2,590	-	0%
Montana	7,792	4,275	12,067		4,275	4,275	7,792	182%
Nevada	62	83	145		83	83	62	75%
New Mexico	60,446	57,173	117,619		57,173	57,173	60,446	106%
North Dakota	4,631	4,739	9,369		4,739	4,739	4,631	98%
Oregon	85	1,182	1,267		1,182	1,182	85	7%
South Dakota	367	323	690		323	323	367	114%
Utah	5,190	3,311	8,500		3,311	3,311	5,190	157%
Washington		1,281	1,281		1,281	1,281	-	0%
Wyoming	19,699	15,015	34,715	6,409	15,015	21,424	13,290	62%
Total	**130,376**	**181,191**	**311,566**	**14,479**	**181,191**	**195,670**	**115,897**	**59%**

*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, 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.

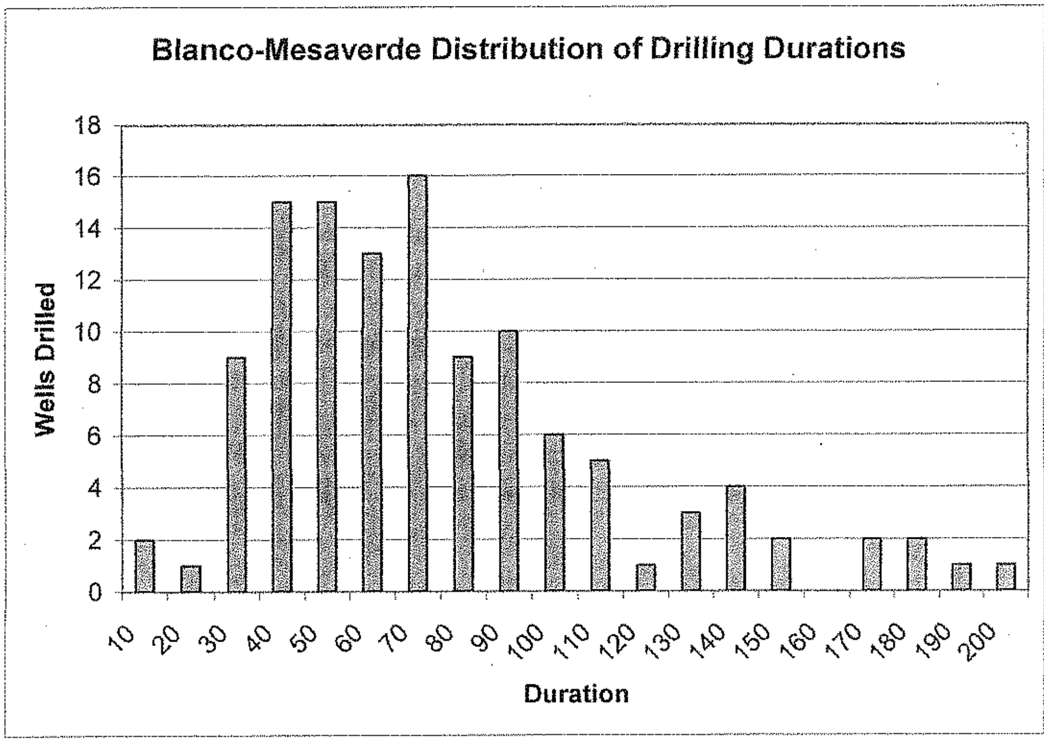


Figure 2-1. Distribution of well preparation activities within a single formation.

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:

$$CE = E \times CW / TW$$

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	48
Arizona			
Colorado	1,244	5,734	260
Idaho			
Montana	463	1,044	227
Nevada	6	24	1
New Mexico	932	6,645	1,444
North Dakota	157	1,536	358
Oregon			
South Dakota	7	36	8
Utah	126	676	147
Washington			
Wyoming	2,948	4,964	1,213
Total	6,088	21,536	3,706

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.

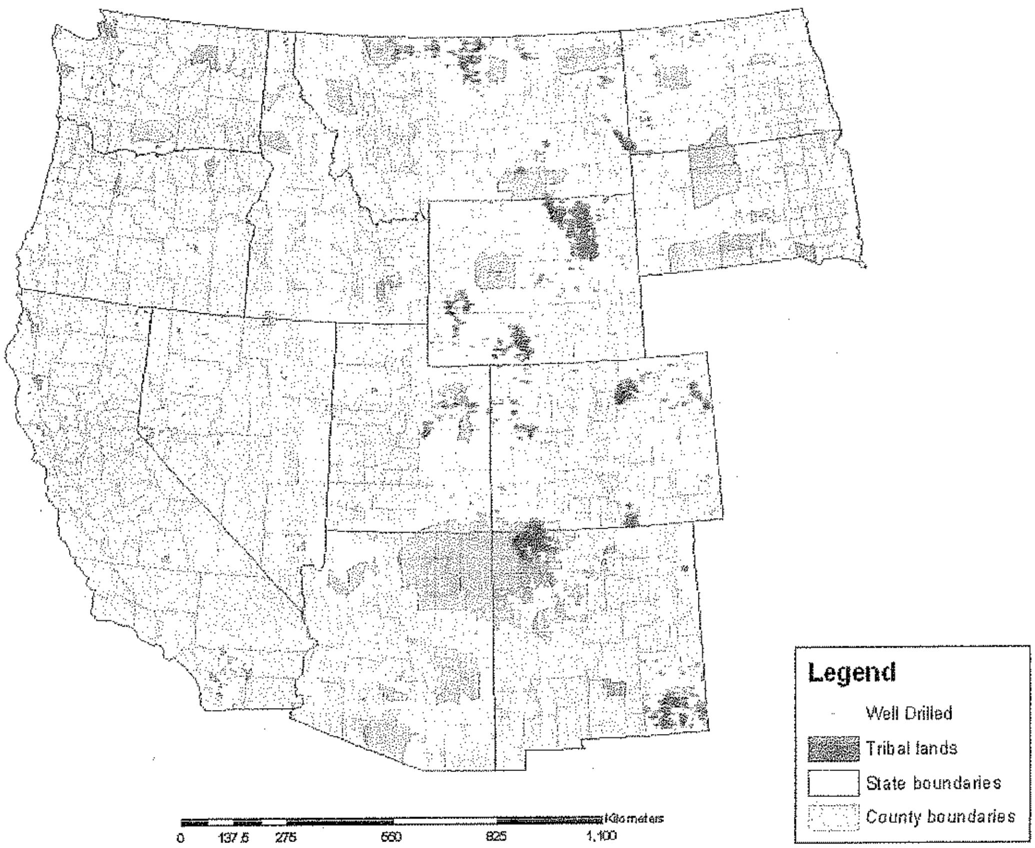


Figure 2-2. Wells drilled in 2002 in the WRAP states.

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.

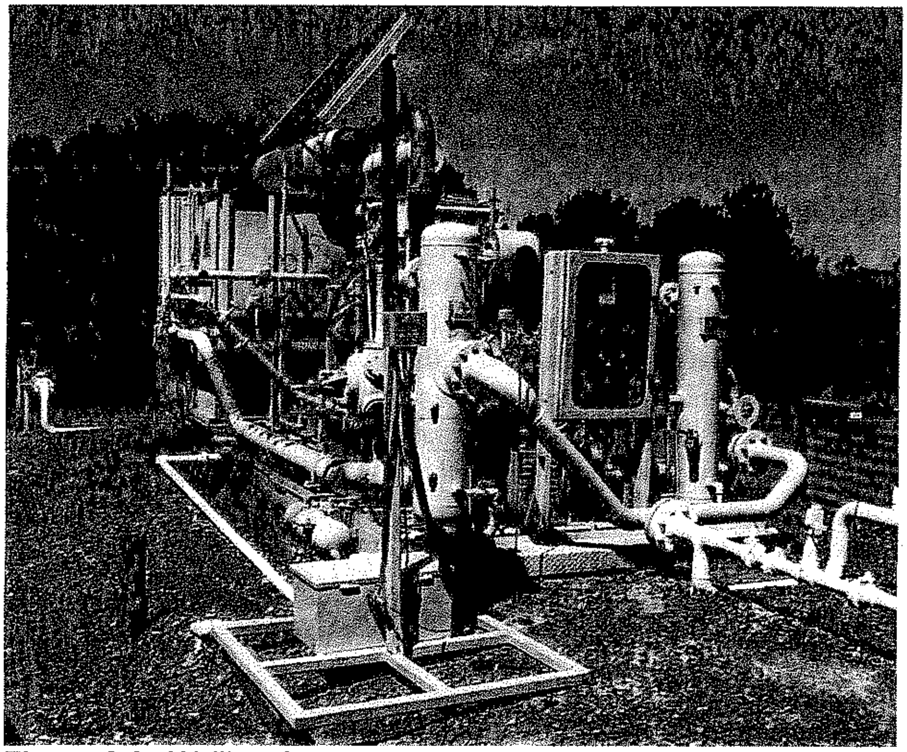


Figure 2-3. Wellhead compressor engine.

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.

<u>2002 Colorado Point Source Emission Inventory</u>

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.

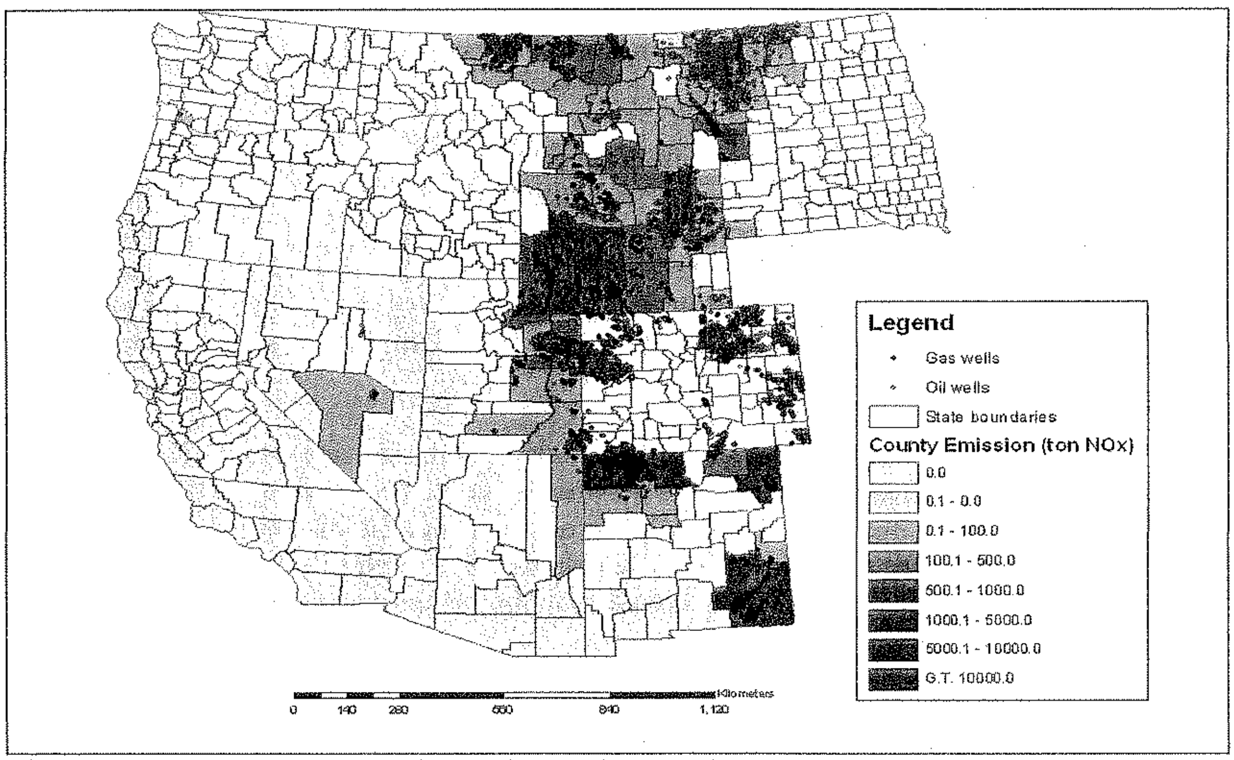
The State total NOx emissions that resulted from the application of these emission factors are presented in Table 2-9. As is shown in Table 2-9, and graphically displayed in Figure 2-4, emissions resulting from this procedure are directly related to production. Though at the level of individual wells 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	-		
Colorado	1,241,311,742	NA	
Idaho	-		
Montana	86,761,832	2.30E-05	2,027
Nevada	6,433	2.30E-05	0
New Mexico	1,716,107,712	2.30E-05	40,095
North Dakota	59,979,925	2.30E-05	1,401
Oregon	837,067	2.30E-05	20
South Dakota	10,955,008	2.30E-05	256
Utah	283,408,406	4.10E-06	1,182
Washington	-		
Wyoming	1,708,567,844	4.10E-06	7,024
Total	8,604,365,099		54,827



*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 2002 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.

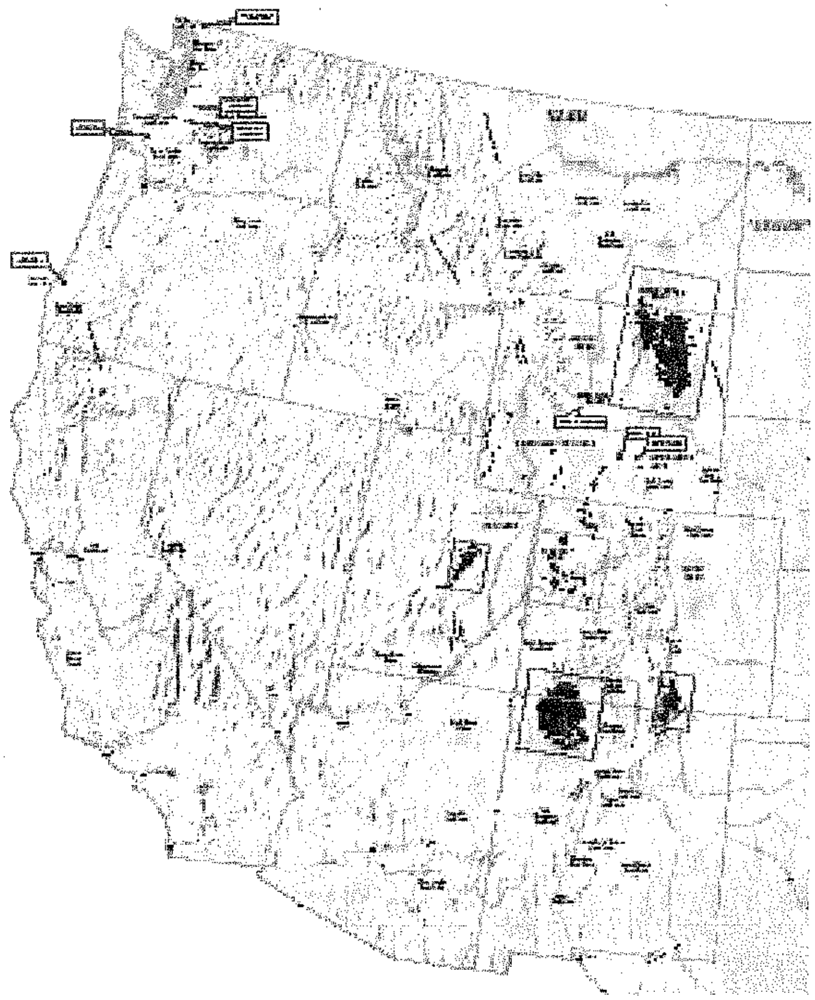


Figure 2-5. Western U.S. Coal bed methane fields (EIA, 2004).

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.

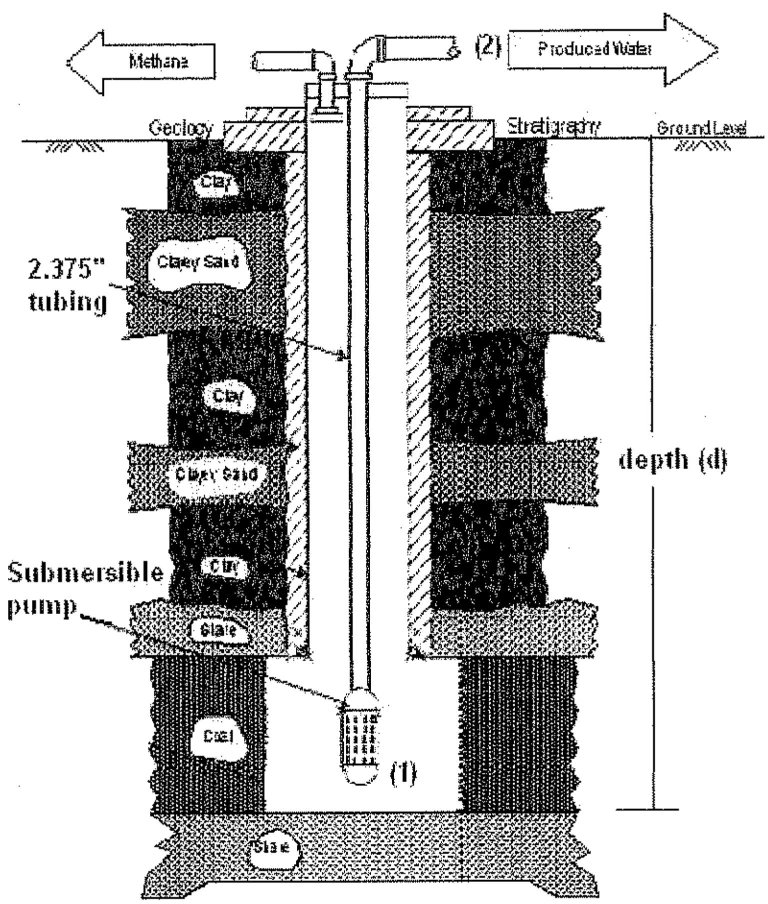


Figure 2-6. Diagram of assumed CBM well.

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
v = 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)
v = 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	3,516	204	20	225
Wyoming	12,147	1,298	130	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.

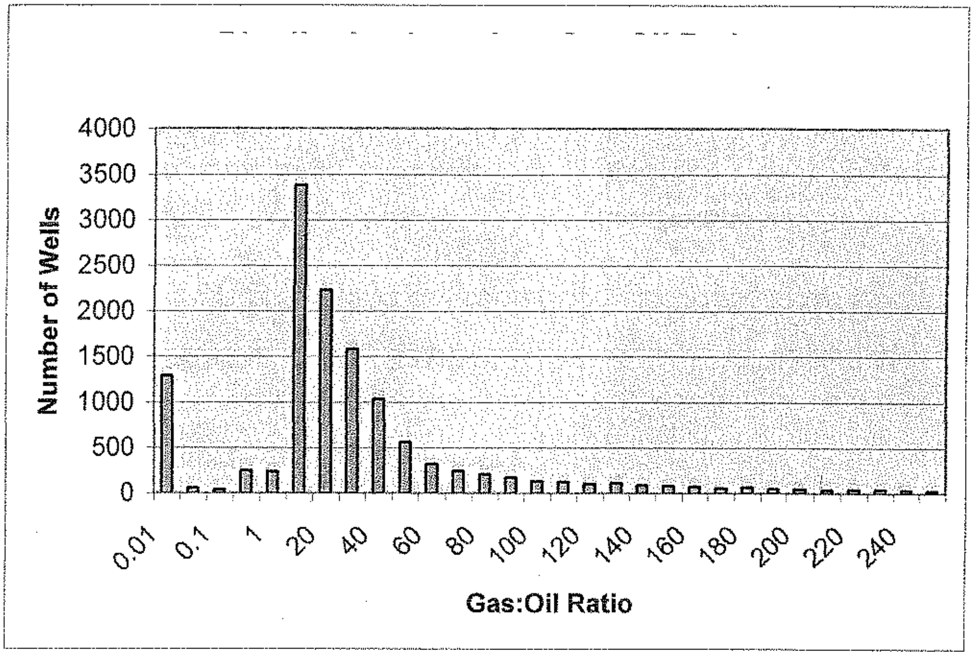


Figure 2-7. Distribution of Colorado wells based on the ratio of gas production to oil production.

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

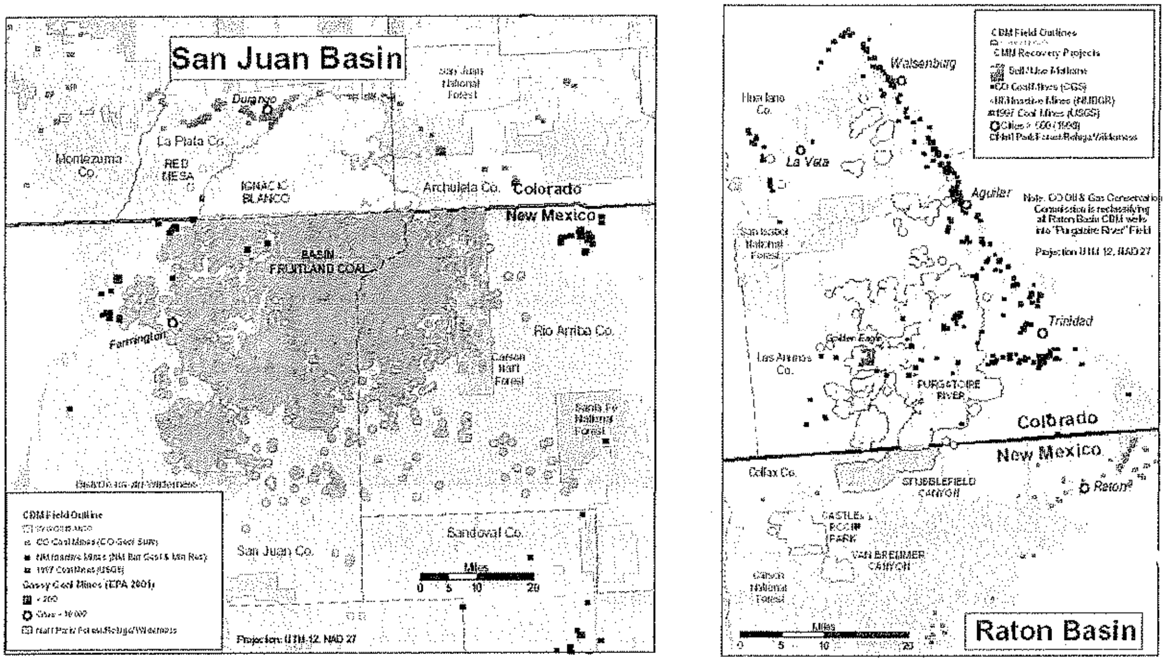


Figure 2-8. Coalbed methane fields in New Mexico.

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 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

<u>VOC Emission Factor</u>

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

<u>NOx Emission Factor</u>

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		
Colorado[2]	25,386	15,924
Idaho		
Montana[3]	5,439	4,721
Nevada	129	5
New Mexico	166,773	13,482
North Dakota	7,740	176
Oregon	34	12
South Dakota	288	47
Utah	34,757	2,143
Washington		
Wyoming	115,027	6,283

[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).

3. SPATIAL ALLOCATION SURROGATES FOR MODELING

For air quality modeling, the EPA default spatial allocation surrogates were not appropriate for the area source oil and gas production emissions. ENVIRON therefore developed a new set of spatial allocation surrogates to be used in SMOKE to allocate the county-level area source emissions to the appropriate oil and gas fields. This section summarizes the development of these new oil and gas spatial allocation surrogates in the WRAP states.

Spatial allocation surrogates were developed for two modeling domains:

36 km	12 km
Origin (-2736, -2088)	Origin (-2376, -936)
NX = 148, NY = 112	NX = 207, NY = 186

As outlined in Table 3-1, twelve oil and gas emission source categories were assigned to one of four different surrogate categories designed to represent the location of emissions. The oil, gas and water production surrogates were based on production data at known well locations, while the drill rig surrogate was based solely on the number and location of wells drilled.

Table 3-1. Emission sources and surrogate categories.

Source	SCC	Allocation Surrogate	Surrogate Code
Drill rigs	2310000220	Drill Rigs	688
Oil well - heaters	2310010100	Oil Production	686
Oil well - tanks	2310010200	Oil Production	686
Oil well - pneumatic devices	2310010300	Oil Production	686
Compressor engines	2310020600	Gas Production	685
Gas well - heaters	2310021100	Gas Production	685
Gas well - pneumatic devices	2310021300	Gas Production	685
Gas well - dehydration	2310021400	Gas Production	685
Gas well - completion	2310021500	Gas Production	685
CBM pump engines	2310023000	Water production at CBM wells	687
Gas well - tanks, uncontrolled	2310030210	Gas Production	685
Gas well - tanks, controlled	2310030220	Gas Production	685

Methods

Latitude and longitude coordinates for oil and gas wells and drill rigs were obtained for the WRAP states, except California. The locations of all wells and drill rigs are shown in Figure 3-1. Also displayed are the boundaries of the Tribal lands of the Arapahoe and Shoshone of the Wind River Reservation, Assiniboine and Sioux of the Fort Peck Reservation, Jicarilla Apache, Navajo, Southern Ute and Ute Mountain Ute. Note that neither Washington nor Idaho had any wells in the database.

Once the well locations were known, creation of the surrogates took place in several steps, and relied on the use of ArcINFO GIS software.

1. All wells and drill rigs were labeled with the appropriate grid cell IJ values for both the 36 and 12 km domains.
2. For each individual well, the oil, gas and water production values were divided by the total oil, gas and water production values corresponding to the county in which the well was located. This division resulted in determination of the fraction of a county's total production taking place at each well. In the case of drill rigs, the number of drills, rather than the production values, were used.
3. For each unique grid cell / county combination with wells, each well's production fractions were summed to create the surrogate value. This step was repeated for both domains separately.

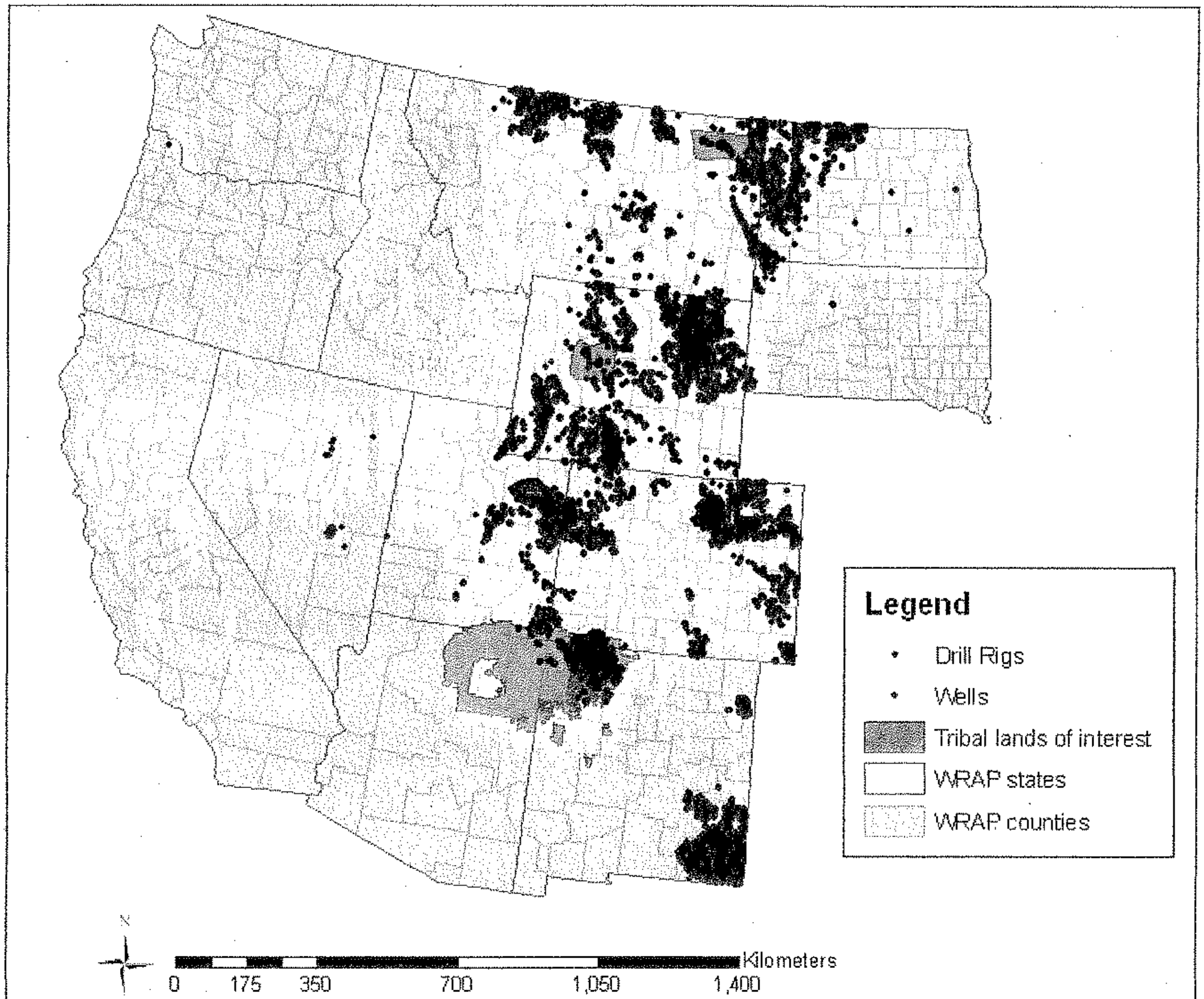


Figure 3-1. Locations of wells and drill rigs.

The surrogate values for each grid cell / county combination were reformatted to comply with the SMOKE emissions processor AGPRO file format. A separate file for each modeling domain was created, and a single accompanying SMOKE AGREF file was created for use with either domain. The purpose of the AGREF file, which is shown in Table 3-2, is to define the relationship between the 3-digit codes chosen to represent each of the four surrogate categories in the AGPRO file and the SCC codes for the twelve oil and gas emission categories to be allocated with these surrogates. This file also specifies which county/state/county (COSTCY) should use the given cross-reference. In this case, COSTCY is set to 000000 to indicate that all states and counties can use these cross-references.

Table 3-2. SMOKE gridding surrogate cross-reference (AGREF) file.

COSTCY	SCC	CODE
000000	2310000220	686
000000	2310010100	688
000000	2310010200	686
000000	2310010300	686
000000	2310020600	686
000000	2310021100	685
000000	2310021300	685
000000	2310021400	685
000000	2310021500	685
000000	2310023000	687
000000	2310030210	685
000000	2310030220	685

Results

To display the surrogates, each grid cell / county surrogate value was multiplied by the county's total production, and then production was summed for each grid cell. Figures 3-2 through 3-5 depict the four different 36 km domain surrogate values; Figures 3-6 through 3-9 depict the 12 km domain surrogate values. These spatial allocation surrogates were used in both the 2002 and 2018 air quality modeling.

Figure 3-10 shows an example daily spatial emissions plot of the 2002 oil and gas emissions as processed through SMOKE.

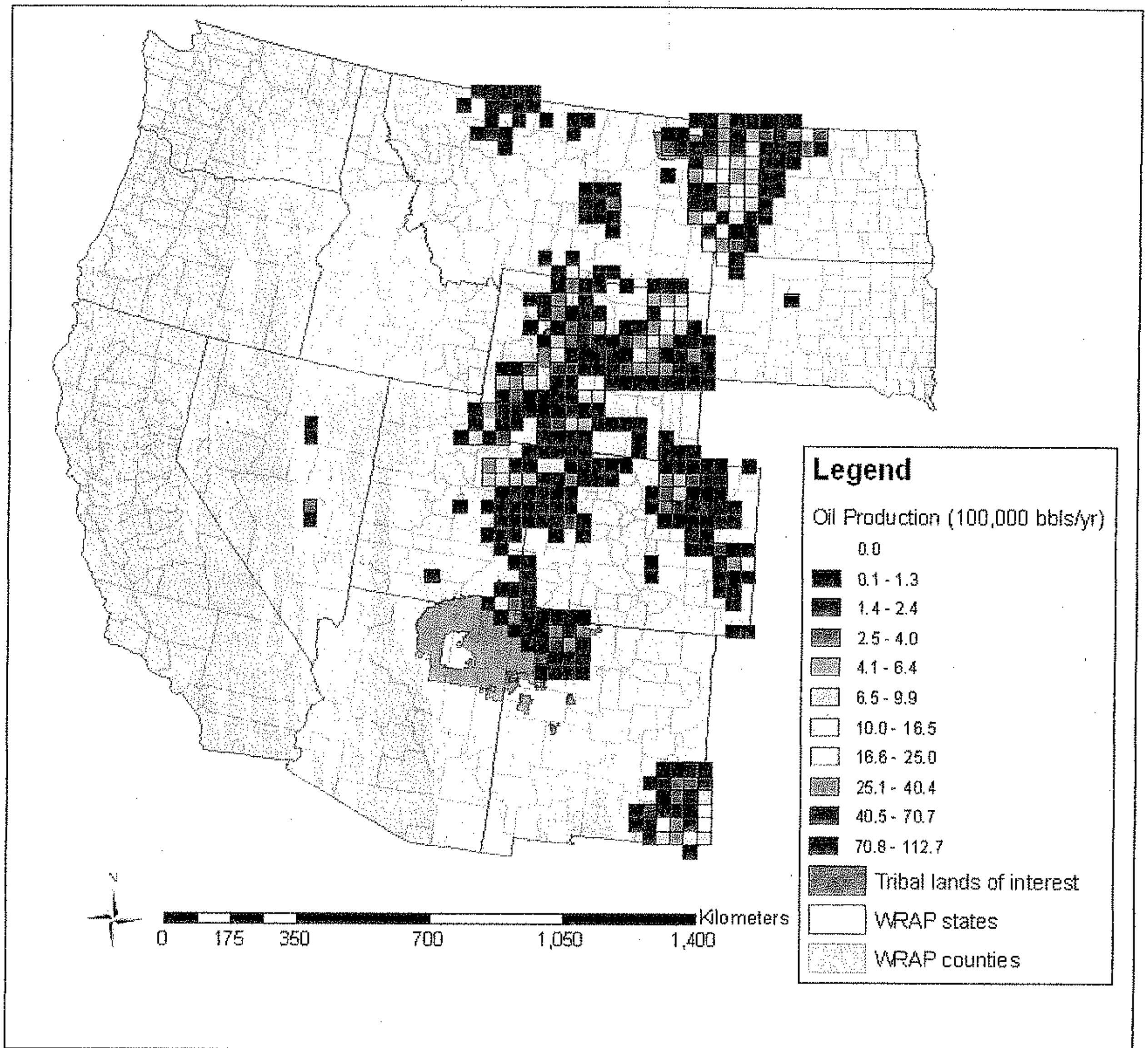


Figure 3-2. Oil production surrogates for the 36 km domain.

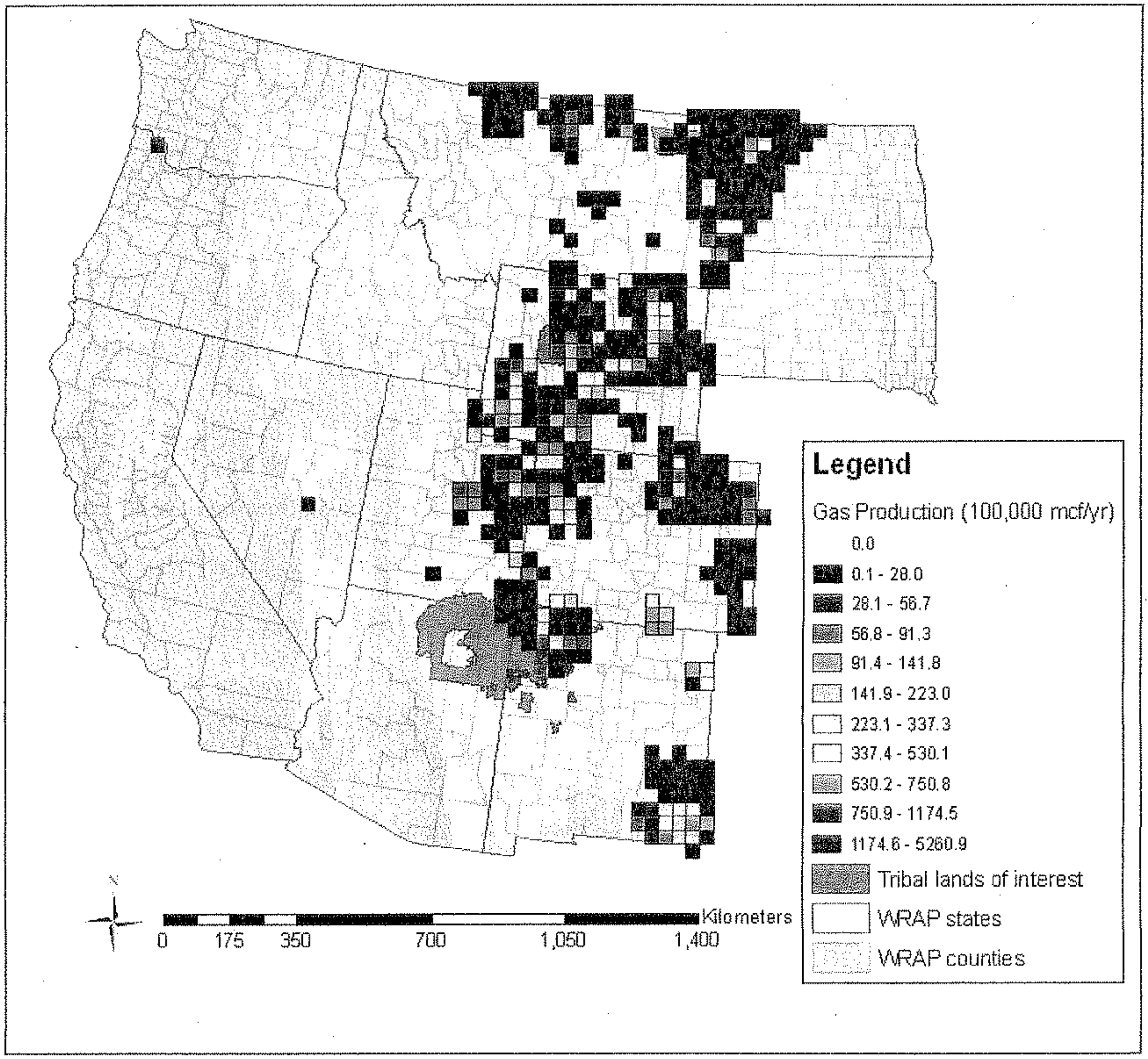


Figure 3-3. Gas production surrogates for the 36 km domain.

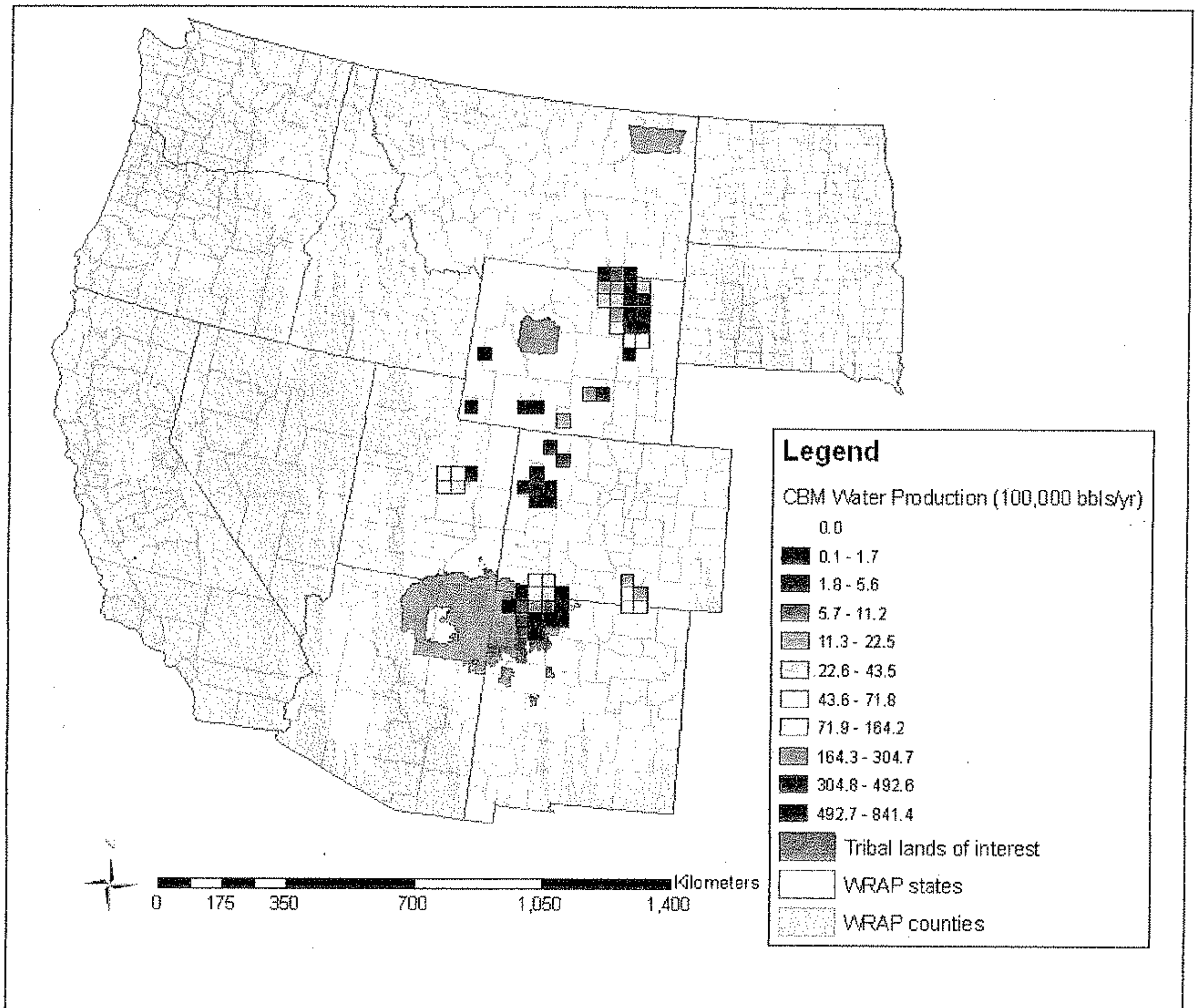


Figure 3-4. CBM well water production surrogates for the 36 km domain.

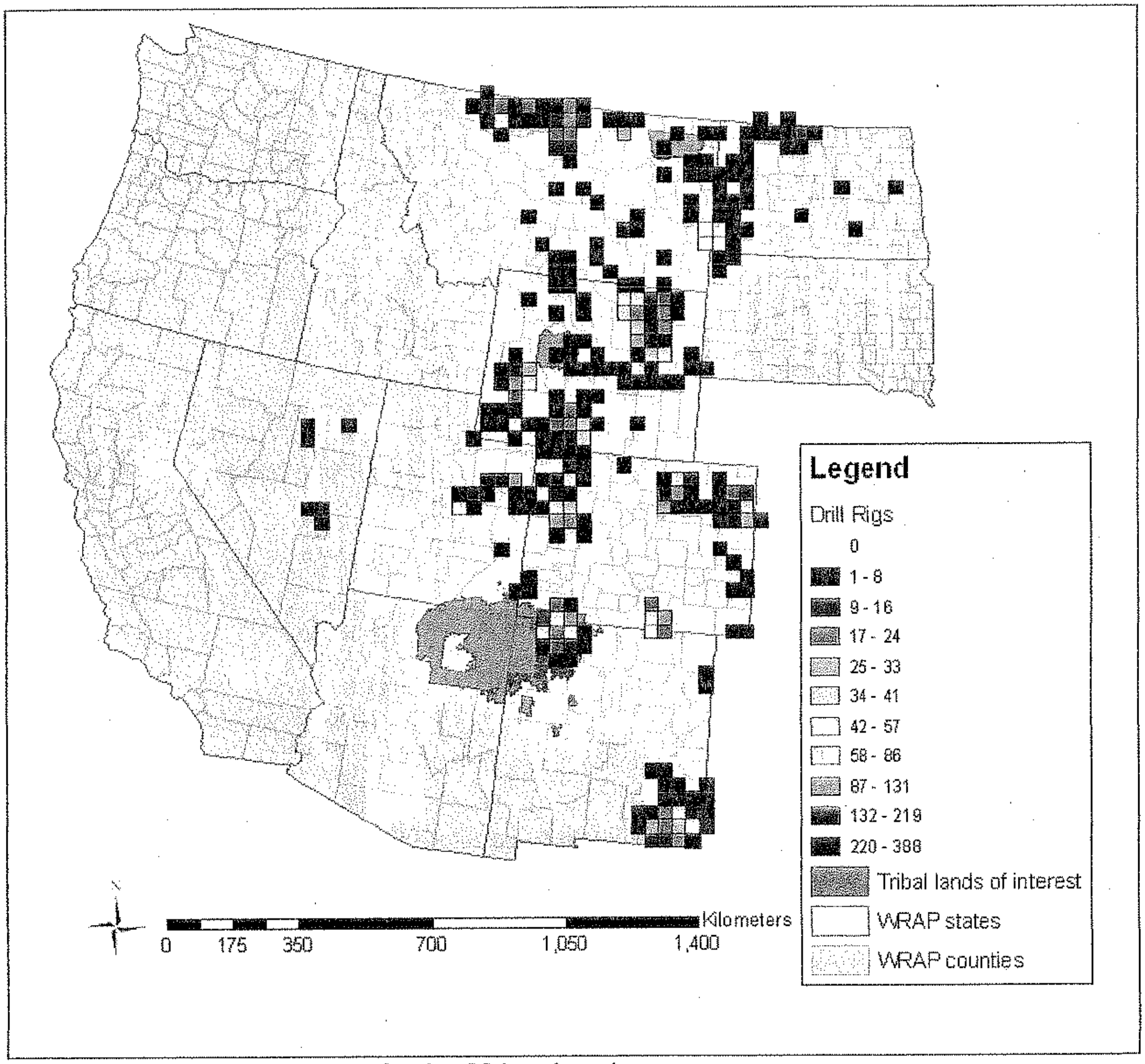


Figure 3-5. Drill rig surrogates for the 36 km domain.

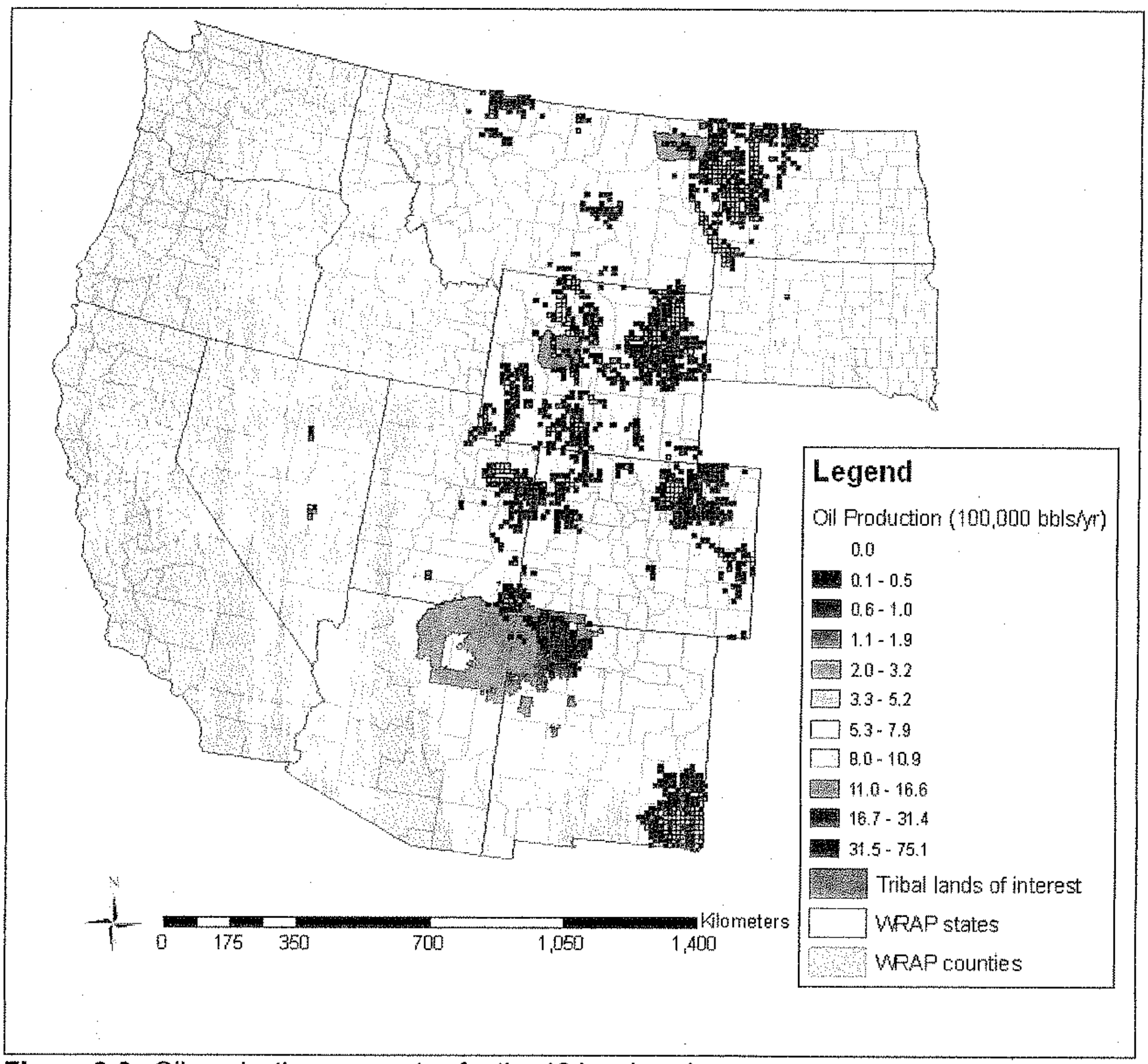


Figure 3-6. Oil production surrogates for the 12 km domain.

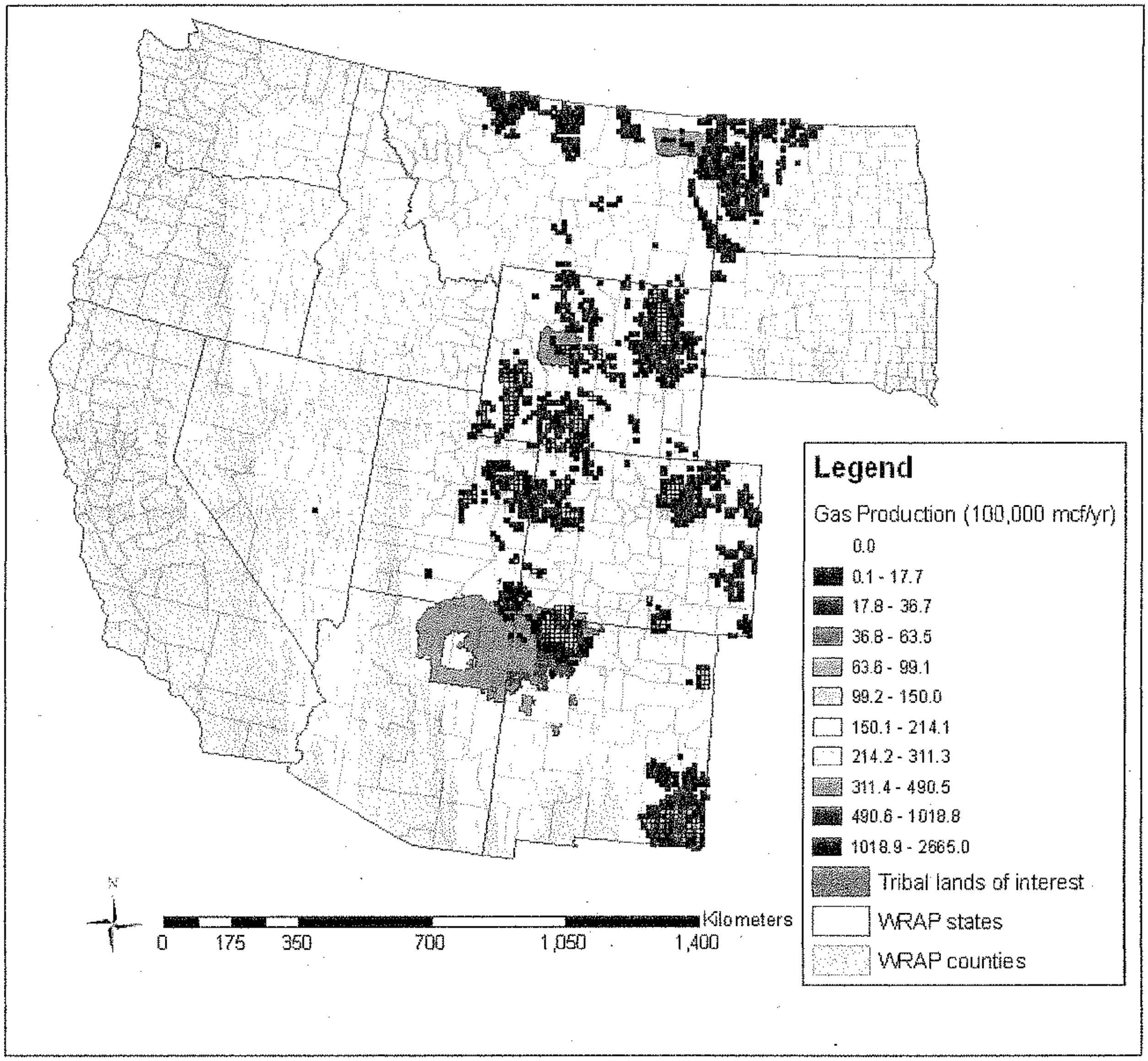


Figure 3-7. Gas production surrogates for the 12 km domain.

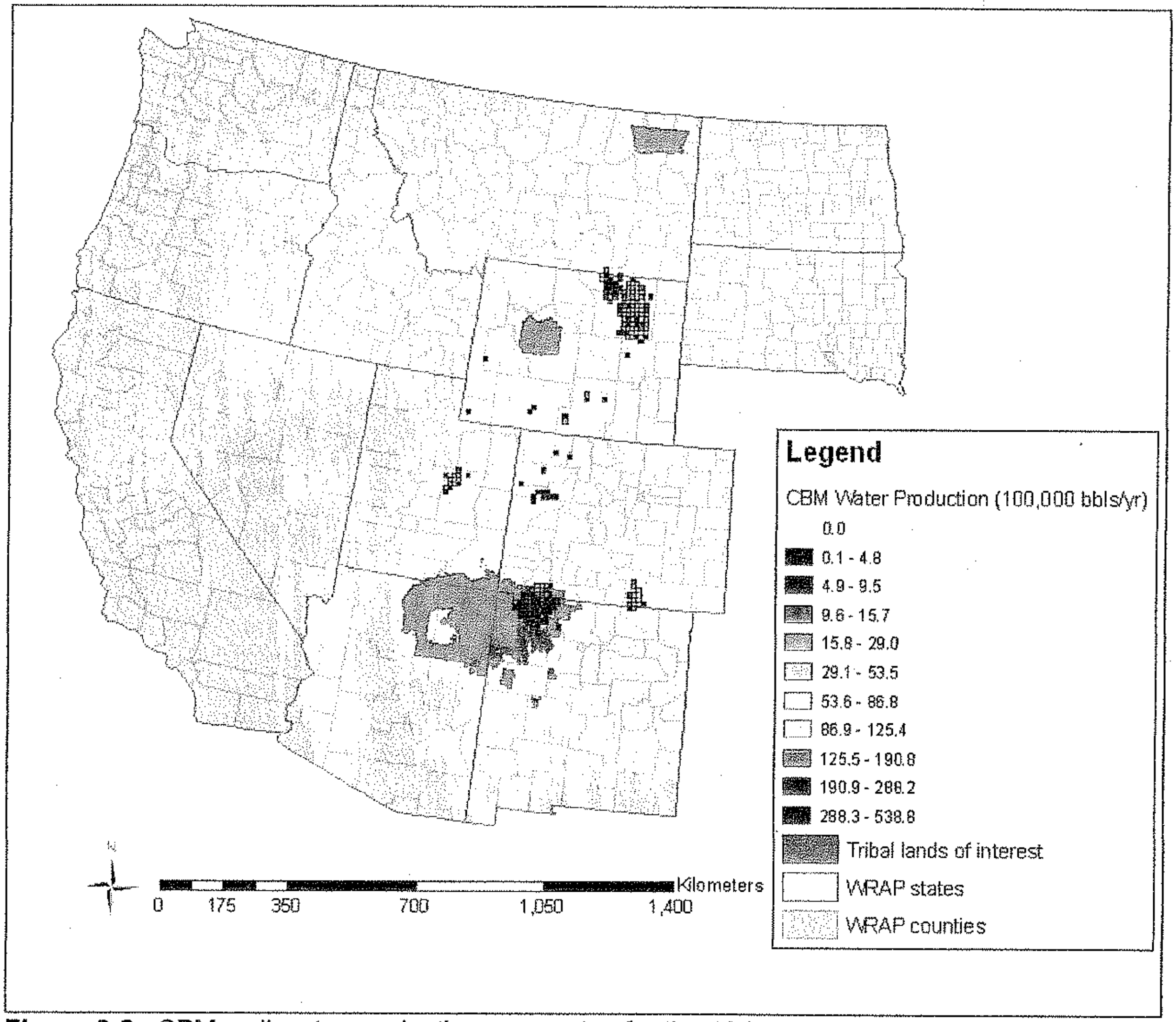


Figure 3-8. CBM well water production surrogates for the 12 km domain.

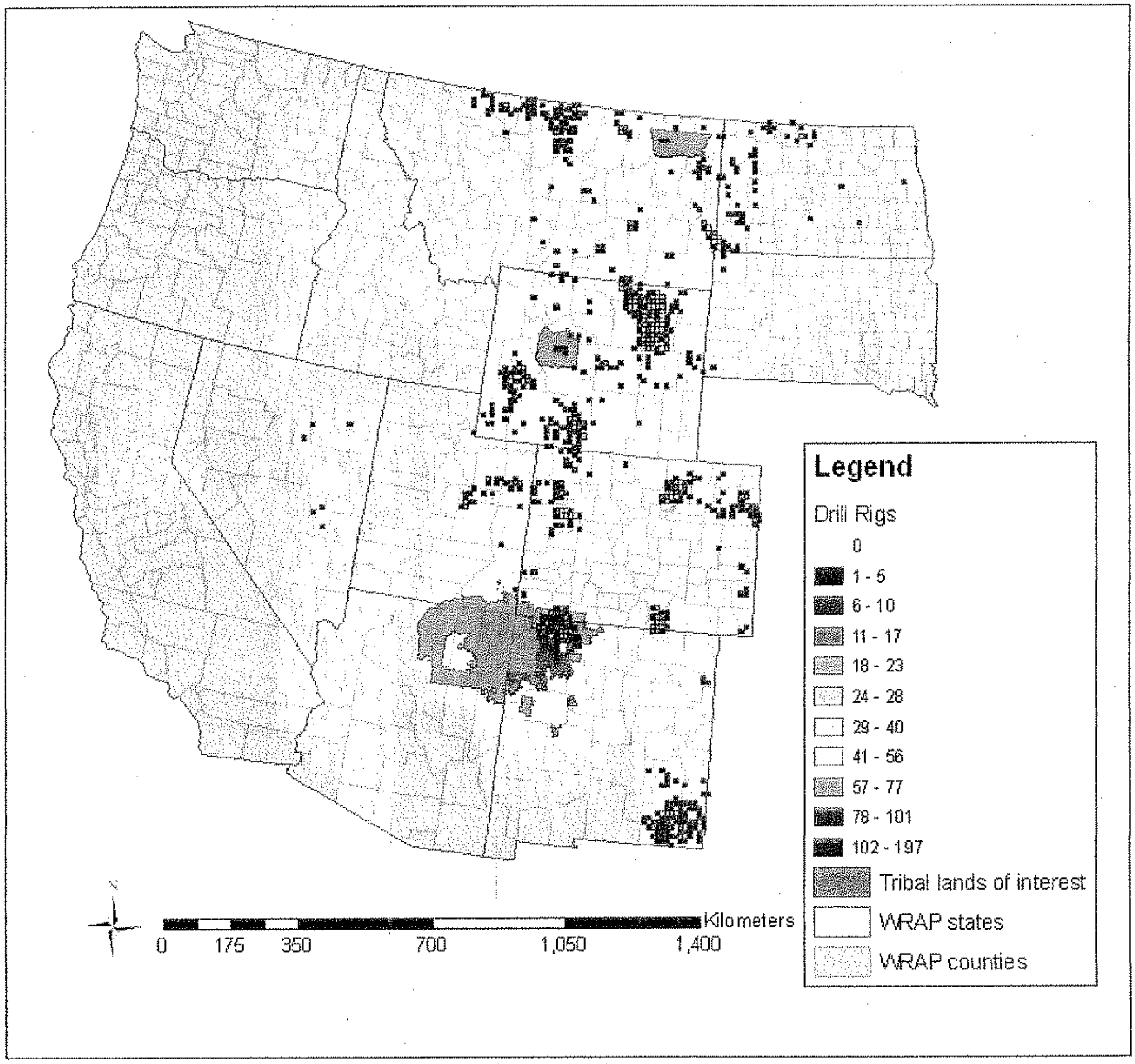


Figure 3-9. Drill rig surrogates for the 12 km domain.

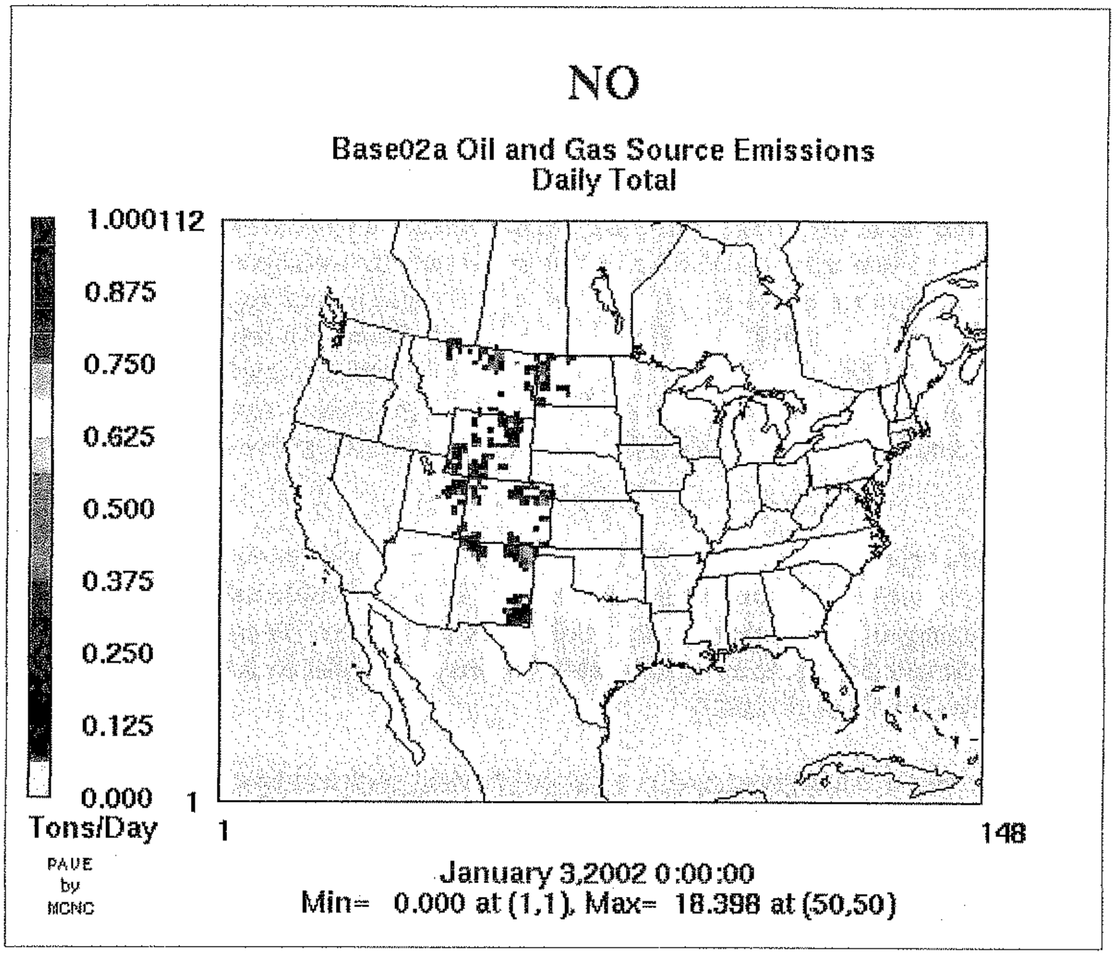


Figure 3-10. Example daily spatial emissions plot of the 2002 oil and gas emissions as processed through SMOKE.

4. 2018 BASE CASE PROJECTIONS

INTRODUCTION

This section describes the methods for estimating the 2018 base case emission inventory of oil and gas area sources for the Western States. This inventory reflects the anticipated 2018 emission levels with the future controls currently defined by state and federal regulation. The 2018 oil and gas point source emissions inventory has been prepared under a separate task, and is reported separately (ERG, 2005b). Thus, while some tables in this section present summaries of the 2018 point source emissions, information about the methodology used to develop those emissions estimates will be found in the report addressing the 2018 point source emissions inventory.

The emissions summaries presented here for the 2018 base case inventory do not include emissions falling under tribal jurisdiction. Under another project, ENVIRON has prepared separate emissions estimates of tribal oil and gas emissions for four tribes. Those emissions estimates have been reconciled with the emissions reported here, and tribal emissions are being reported separately (ERG/ENVIRON, 2005).

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 here is the State of California. The California Air Resources Board (CARB) has provided point and area source oil and gas emissions projections directly to WRAP. Those estimates have been adopted by this inventory and are considered to be complete.

Table 4-1a presents a summary of the estimated 2018 NOx emissions from oil and gas area point and area sources in the WRAP States. Table 4-1b presents a similar summary of VOC emissions. The area source emissions are distinguished by source category, except in California where only the total NOx emission from the ARB inventory is given. The point source emissions included in Tables 4-1a and 4-1b include several types of oil and gas facilities that are listed under SIC codes 13**, 492* or 4612. In most states, the major contributors of point source oil and gas emissions are natural gas transmission stations and natural gas processing plants. Crude oil pump stations and large storage sites also make a significant contribution in some states. Notably, the point source inventory methods in the State of Colorado and the State of Alaska are such that the majority of oil and gas emissions sources are included in the point source inventory.

Table 4-1a. 2018 State total NOx emissions (tons) from oil and gas sources.

State	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source Total	Point Source Total	TOTAL
Alaska		566	2		568	36,501	37,069
Arizona						3,468	3,468
California						13,390	13,390
Colorado		4,051	23,474	184	27,709	15,832	43,541
Idaho						1,734	1,734
Montana	19,029	3,630	7,631	240	30,529	2,554	33,084
Nevada	48	17	7		72	139	212
New Mexico	102,260	7,850	28,420	21	138,551	36,323	174,874
North Dakota	6,751	1,293	633	1	8,678	2,946	11,624
Oregon	42	-	7		48	608	656
South Dakota	414	25	68		507	311	818
Utah	4,736	2,212	6,225	1	13,174	2,314	15,488
Washington						703	703
Wyoming	32,729	7,437	18,466	901	59,533	9,713	69,246
Total	**166,009**	**27,082**	**84,932**	**1,348**	**279,370**	**126,536**	**405,907**

Table 4-1b. 2018 State total VOC emissions (tons) from oil and gas sources.

State	Oil Well, Tanks - Flashing & Standing/Working/Breathing	Oil Well, Pneumatic Devices	Gas Well, Pneumatic Devices	Gas Well, Dehydrators	Gas Well, Completion - Flaring and Venting	Condensate Tanks, Uncontrolled	Condensate Tanks, Controlled	Area Source Total	Point Source Total	TOTAL
Alaska					92			92	2,112	2,204
Arizona									345	345
California									4,962	4,962
Colorado	973	176	4,997		30,912			37,058	59,436	96,494
Idaho									114	114
Montana	4,938	471	1,507	-	637	-	2	7,556	1,024	8,580
Nevada	162	9	1	0	-	-	-	173	32	205
New Mexico	9,357	1,345	5,981	97,981	103,954	110,028	-	328,647	18,339	346,986
North Dakota	8,227	415	120	3,370	659	-	261	13,052	262	13,315
Oregon	-	-	2	18	-	-	-	19	23	42
South Dakota	329	16	15	28	-	-	-	387	38	426
Utah	3,960	304	1,153	13,666	55,569	20,634	-	95,286	3,028	98,314
Washington									36	36
Wyoming	11,369	1,196	3,586	195,221	129,292	62,501	1,469	404,633	10,155	414,788
Total	**39,315**	**3,932**	**17,361**	**310,285**	**321,115**	**193,163**	**1,732**	**886,904**	**99,907**	**986,811**

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 4-2 compares the results of the 2018 oil and gas inventory with the 2002 oil and gas emissions inventories for NOx. Area source NOx emissions estimated for 2018 show a 114 percent increase over 2002 levels. In the total oil and gas emissions, this large increase in area source emissions is partially offset by a greater than 50 thousand ton decrease in NOx emissions predicted for point sources. The area source and overall increases are most substantial in places where recent development plans predict large-scale oil and gas projects in future years. Such is the case in Montana and Wyoming where major development is anticipated for the Powder River Basin and the Jonah-Pinedale area.

Table 4-2. Change in oil and gas NOx emissions from 2002 to 2018.

State	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source Total	Point Source Total	TOTAL
Alaska		-35%	-79%		-36%	-20%	-21%
Arizona						27%	27%
California						-20%	-46%
Colorado		-29%	47%	-88%	20%	-39%	-11%
Idaho						-33%	-33%
Montana	839%	248%	62%		292%	-40%	174%
Nevada	46%	-31%	42%		16%	68%	46%
New Mexico	155%	18%	111%	-91%	129%	-36%	49%
North Dakota	131%	-16%	261%		87%	-38%	24%
Oregon	-43%	0%	-43%		-43%	-49%	-48%
South Dakota	46%	-31%	45%		38%	-4%	19%
Utah	100%	227%	191%		154%	-30%	82%
Washington						-45%	-45%
Wyoming	366%	50%	194%	-37%	202%	-35%	99%
Total	**203%**	**26%**	**98%**	**-57%**	**114%**	**-30%**	**30%**

AREA SOURCE OIL AND GAS GROWTH FACTORS

At the most basic level there were two methods used to estimate 2018 county-level oil and gas emissions. The first and by far the dominant method was to develop growth factors that were then used to project from the 2002 oil and gas emissions. A second method was necessary to estimate emissions in the handful of counties that had no 2002 oil and gas emissions but are anticipated to see oil and gas development by 2018. The decision of which method was used to estimate 2018 emissions was based on the existence of oil and gas emissions in 2002. Discussion of the method used for the group of counties with no emissions in 2002 is reserved for later in this section. Here, the data sources and methodologies are presented that were used to project 2002 emissions to 2018 for the three conditions where oil and gas emissions were present in 2002.

Production Growth Factors

The projection of emissions from 2002 to 2018 required the development of county-level growth factors. These growth factors were derived from projections of future oil and gas production reported by several sources. The preferred source of production projections was the Bureau of Land Management (BLM). The BLM periodically prepares Resource Management Plans (RMP) for the lands and mineral resources under its stewardship. RMP for oil and gas production areas typically include an estimate of reasonable foreseeable oil and gas development. The future development is usually estimated as a number of new oil, gas and possibly CBM wells anticipated over the next 10 or 20 years. Table 4-3 provides a brief summary of the reasonable foreseeable development (RFD) scenarios that were ultimately used to obtain the necessary information for creating the 2002 to 2018 growth factors.

Table 4-3. BLM Resource Management Plans considered for use in projections.

RMP ID	RMP_NAME	Source	Start Date	End Date	Gas Wells	Oil Wells	CBM Wells	Wells Drilled
1	Northern San Juan Basin Coal Bed Methane Project	USDA FS, 2004	1/1/2004	1/1/2018			296	296
2	Pinedale RMP	WY BLM, 2005	1/1/2006	1/1/2025	9800			9800
3	Wyoming Powder River Basin Final EIS	WY BLM, 2001	1/1/2002	1/1/2022			81000	81000
4	White River Resource Area RMP EIS	CO BLM, 1996	1/1/1996	1/1/2016	919			1100
5	RMP EIS for Mineral Leasing and Development in Sierra and Otero Counties	NM BLM, 2003	1/1/2003	1/1/2023	36	48		105
6	Dakota Prairie Grasslands Oil and Gas Leasing	USDA FS, 2003	1/1/2003	1/1/2013	450		60	660
7	Farmington Proposed Resource Management Plan	NM BLM, 2003	1/1/2002	1/1/2022	13271	380	2964	16615
8	Desolation Flats Natural Gas Field Development Project	WY BLM, 2004	1/1/2004	1/1/2024	308			474
9	Draft Vernal Resource Management Plan	UT BLM, 2005	1/1/2006	1/1/2021	4345	2055	130	6530
10	Jack Morrow Hills Coordinated Activity	WY BLM, 2004b	7/1/2004	1/1/2021	107		50	255
12	Wind River Natural Gas Project	BIA, 2004	1/1/2005	1/1/2018	325			325
13	Powder River and Billings Resource Management Plan	MT DEQ, 2003	1/1/2003	1/1/2023	800		18200	19000
14	Powder River and Billings Resource Management Plan	MT DEQ, 2003	1/1/2003	1/1/2023	250		6400	6650
15	Powder River and Billings Resource Management Plan	MT DEQ, 2003	1/1/2003	1/1/2023	150			150

As shown in Table 4-3, we obtained a number of RMPs covering a large portion of the WRAP production areas. Figure 4-1 shows the approximate area covered by these resource management plans. Despite the broad combined coverage of these plans, there are some significant production areas for which management plans could not be located.

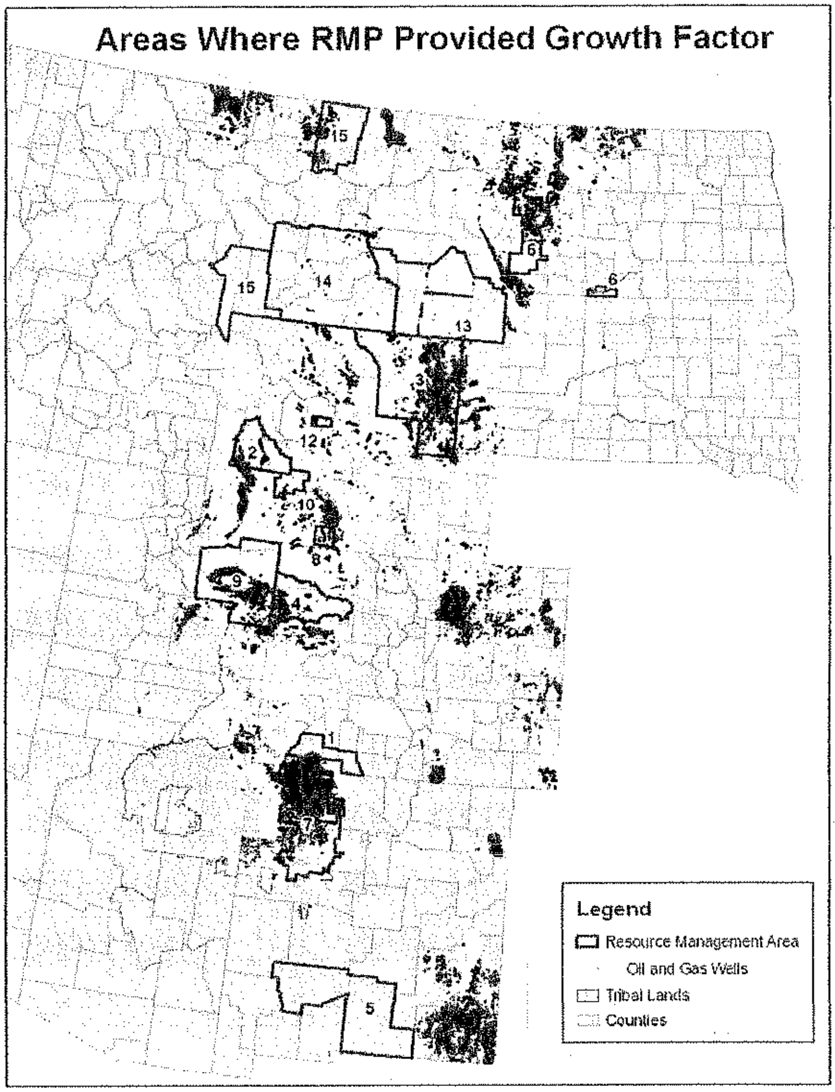


Figure 4-1. Coverage of resource management plans ultimately used to create growth factors.

For some of the areas where it was not possible to obtain recent local development forecasts from the BLM, other sources of local data were identified. For example, the Alaska Department of Natural Resources (AK DNR, 2004) prepares 20-year production forecasts that were used in this effort. Other local sources of data were considered, but were ultimately discarded due either to a lack of detail, the reporting of only the next two or three years, or for a combination of inadequate detail and time-span. Thus, for the areas not covered by the RMP listed in Table 4-3 and not in the State of Alaska, regional production forecasts published by the Energy Information Administration (EIA, 2005b) were used.

The EIA has published projection forecasts out to 2025. For production areas where EIA forecasts were the only source of data identified, separate oil and gas growth factors have been calculated as the 2018 regional production forecast by the EIA divided by 2002 regional production reported by the EIA. There are three EIA growth regions in which some portion of emissions in that region were projected using EIA data. Those regions are the Rocky Mountain Region, the Southwest Region and the West Coast Region. Growth factors developed for those regions based on the EIA's production forecasts are shown in Table 4-4. The delineation of those regions is shown in Figure 4-2.

Table 4-4. 2002 to 2018 oil and gas growth factors based on EIA forecasts.

Region	Oil Production	Gas Production
Rocky Mountain	1.334	1.458
Southwest	0.866	1.354
West Coast	0.601	0.568

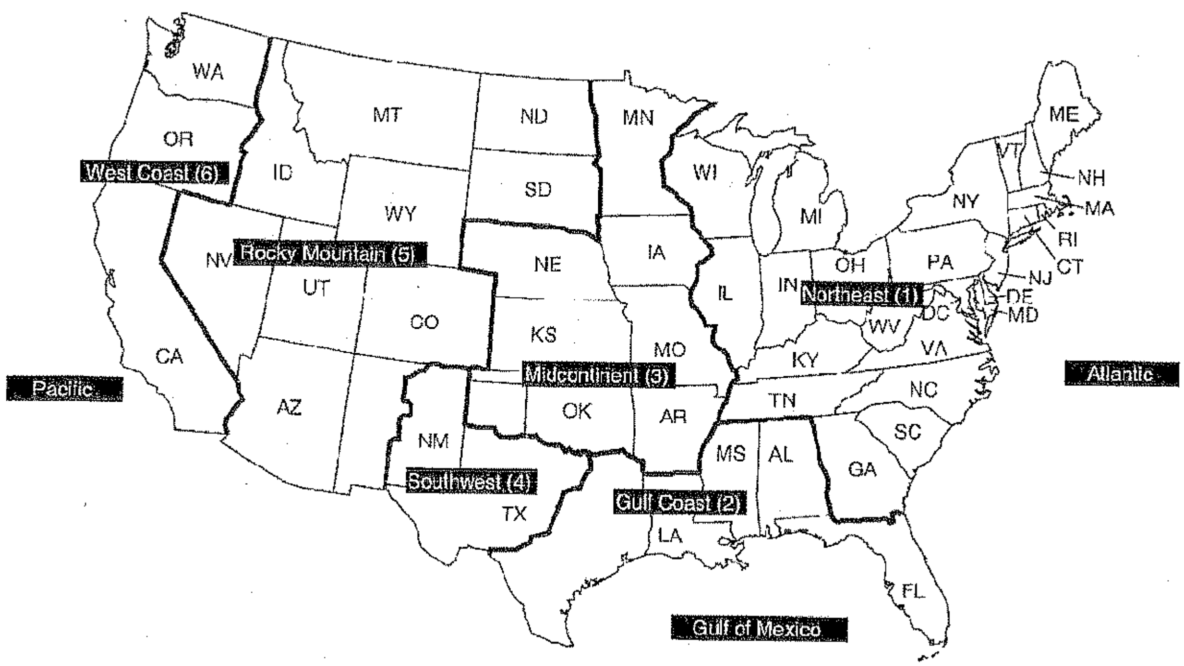


Figure 4-2. EIA production forecasting regions.

Projections to 2018 based on the BLM resource management plans or Alaska DNR data were made using growth factors derived from the proposed future development and the actual 2002 activity. In order to estimate the future number of wells, both the number of wells installed and the number of wells plugged and abandoned had to be estimated. The RMPs do not include estimates of the number of wells that will be plugged and abandoned in future years. The historical plugging and abandoning of wells was, however, available from the OGCs. Thus, lacking other projections of future well abandonment, we used OGC data to estimate the number of wells plugged and abandoned annually at the county level. We then developed an estimate of the future number of wells in a production area based on the number of existing wells in 2002, the number of new wells anticipated by the RMP and the estimated number of wells that would be abandoned based on the assumed persistence of historical abandonment rates. The calculation of a growth factor was thus accomplished as shown in Calculation 1.

Calculation 1: Determination of CBM, oil and gas well growth factor based on BLM RMP

$$G = \frac{(W_{02} + W_f - W_P)}{W_{02}}$$

where:

G = the 2002 to 2018 growth factor
W_{02} = the wells (oil/gas/CBM) active in 2002
W_f = the wells (oil/gas/CBM) forecast to be added by 2018
W_P = the wells (oil/gas/CBM) estimated to be plugged and abandoned by 2018

Because gas production at all well types drives compressor emissions, none of the three growth factors developed for oil wells, gas wells or CBM wells was alone representative of growth in compression. Compressor engine emissions needed to be projected based on the total growth in gas production. Thus a growth factor for total gas production was developed as shown in Calculation 2.

Calculation 2: Derivation of a gas production growth factor based on BLM RMP

$$G_{gas} = \frac{\sum_i (W_{02,i} + W_{f,i} - W_{P,i}) * P_i}{\sum_i P_i * W_{02,i}}$$

where:

i refers to the three well types: oil, gas and CBM
G_{gas} = the 2002 to 2018 growth factor
P_i = the average 2002 production of an oil/gas/CBM well
$W_{02,i}$ = the oil/gas/CBM wells active in 2002
$W_{f,i}$ = the oil/gas/CBM wells forecast to be added by 2018
$W_{P,i}$ = the oil/gas/CBM wells estimated to be plugged and abandoned by 2018

In areas with coverage by a RMP, a separate growth factor was estimated for drill rig activity as the number of wells drilled per year suggested by the development scenario divided by the number of wells drilled in the same area in 2002. A growth factor for drilling in areas where EIA forecasts were used was determined based on the total predicted growth in well drilling in the lower 48 states as reported the EIA forecast, as regional drilling growth was not available. 27.25 thousand wells are anticipated to be drilled in the lower 48 states in 2018, versus 25.45 thousand wells drilled in 2002. From this information a drill rig activity growth factor of 1.071 was calculated.

A total of eight types of growth factors were used to project 2018 oil and gas emissions; three types were developed from EIA forecasts, and five types were based on local production projections. A summary of these eight types of growth factors is presented in Table 4-5. The estimation of emissions in the year 2018 using these growth factors is discussed below.

Table 4-5. Projection growth factors.

ID	Data Source	Growth Factor	Derivation
G1	EIA	Gas production	2018 estimated gas production for the region divided by 2002 gas production for the region
G2	EIA	Oil production	2018 estimated oil production for the region divided by 2002 gas production for the region
G3	EIA	Well drilling	2018 estimated wells drilled in the lower 48 divided by 2002 wells drilled in the lower 48
G4	Local	Gas wells	2018 estimated gas wells in the planning area divided by 2002 gas wells in the planning area (Calculation 1)
G5	Local	Oil wells	2018 estimated oil wells in the planning area divided by 2002 oil wells in the planning area (Calculation 1)
G6	Local	CBM wells	2018 estimated CBM wells in the planning area divided by 2002 CBM wells in the planning area (Calculation 1)
G7	Local	Gas production	2018 estimated total gas production in the planning area divided by total 2002 gas production in the planning area (Calculation 2).
G8	Local	Well drilling	Number of wells drilled per year suggested by the development forecast divided by the number of wells drilled in 2002

2018 Emissions Projections

In all counties having 2002 emissions for a given oil and gas area source process, the 2018 emissions estimate for that process was made by applying a growth factor to the 2002 emissions and then adjusting the estimate to incorporate future year controls. As growth factors were developed for production areas rather than counties, it was necessary to intersect the production areas with the WRAP counties to determine which growth factor to apply in each county. This intersection yielded three distinct conditions: Counties entirely within a RMP area, counties partially within an RMP area and counties not in a RMP area. In the counties only partially intersected by a RMP area, it was necessary to apply BLM-based growth factors to the fraction of the wells in the RMP area and EIA-based growth factors to the remaining wells. The general formula used to estimate 2018 emissions for the process-specific emissions estimates is presented in Calculation 3. Which of the eight growth factors were applied to each of the emissions sources is stipulated in Tables 4-6 and 4-7.

Calculation 3. General formula for projecting process-specific emissions estimates

$$E_{18} = G * E_{02}$$

where:

E_{18} = the emissions from a process in 2018

G = the growth factor for the process, as indicated in Tables 4-6 and 4-7

E_{02} = the emissions from a process in 2002

Table 4-6. Growth factor used for each source in areas where local plans were used.

Source	Growth Factor*
Compressor Engines	Local Gas Production (ID = G7)
CBM Pump Engines	Emissions grown based on CBM well growth factor (ID = G6)
Oil Well - Minor NOx & VOC sources	Emissions grown based on oil well growth factor (ID = G5)
Gas Well - Minor NOx & VOC sources	Emissions grown based on gas well growth factor (ID = G4)
Drill Rigs	Emissions grown based on growth in number of wells drilled annually (ID = G8)

* IDs correspond to those assigned in Table 4-5

Table 4-7. Growth factor used for each source in areas where EIA data were used.

Source	Growth Factor*
Compressor Engines	Emissions grown based on gas production growth factor (ID = G1)
CBM Pump Engines	Emissions grown based on gas production growth factor (ID = G1)
Oil Well - Minor NOx & VOC sources	Emissions grown based on oil production growth factor (ID = G2)
Gas Well - Minor NOx & VOC sources	Emissions grown based on gas production growth factor (ID = G1)
Drill Rigs	Emissions grown based on growth in wells drilled (ID = G3)

* IDs correspond to those assigned in Table 4-5

Figure 4-3 shows a sample of how different growth rates would be applied to areas that, while physically near each other, fell in distinct EIA forecast regions or one inside and the other outside of a RMP area. Figure 4-4 then displays the growth factors developed for gas production in the WRAP states. A complete list of the growth factors developed to project 2002 area source oil and gas emissions to 2018 is provided as Appendix D.

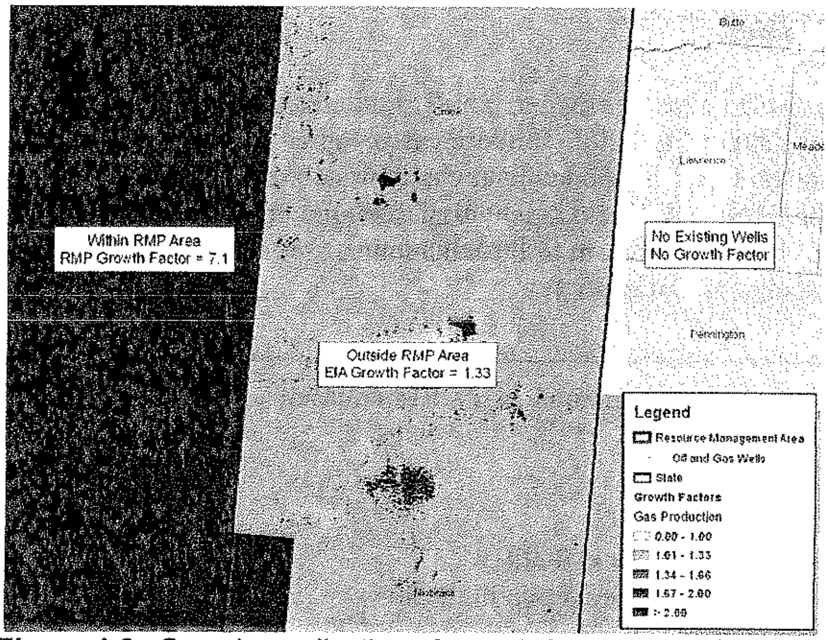


Figure 4-3. Sample application of growth factors derived from RMP and from EIA sources.

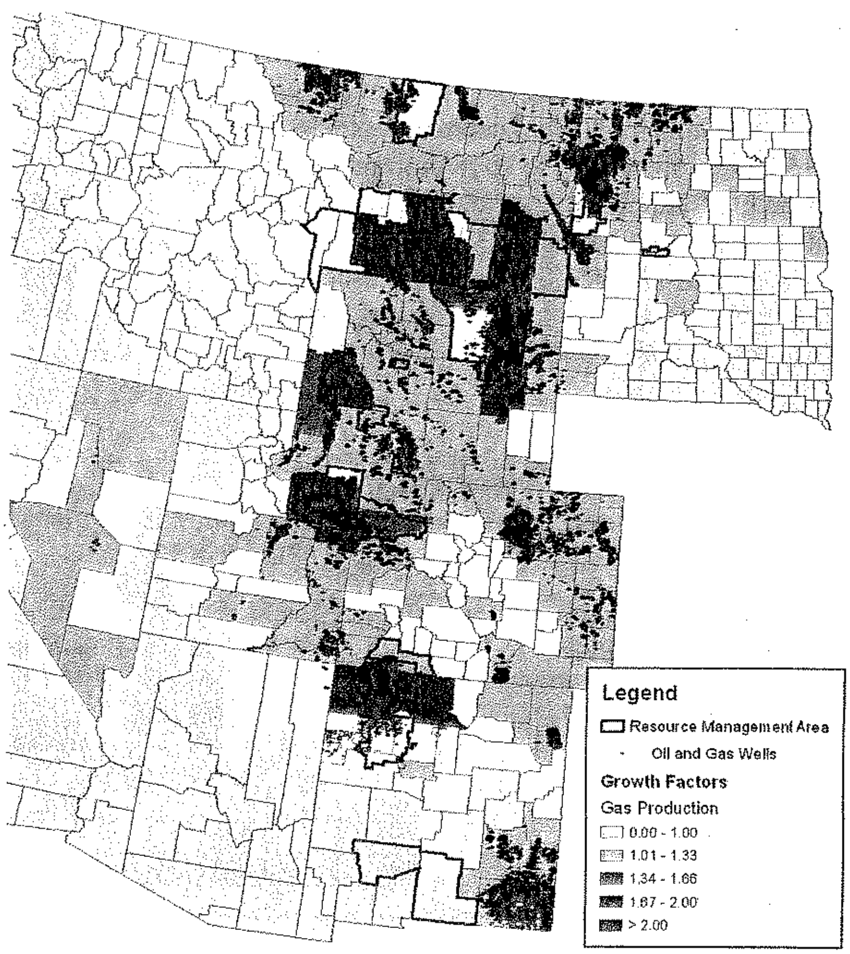


Figure 4-4. Growth factors developed to represent growth in gas production in WRAP region.

Independent 2018 emissions estimates

As is apparent in Figure 4-3, there were some areas where an RMP predicted oil and gas development, but no oil or gas wells existed in 2002. In those cases, the growth factor approach could not be applied. Instead, a method was developed whereby emissions were estimated based on the development forecast by the RMP and the average emissions associated with similar oil and gas sources in the same State. The general form of the calculation used to estimate 2018 emissions in these counties is presented as Calculation 4.

Calculation 4. General formula for independent estimates of 2018 emissions

$$E_{18,P} = D_P * E_{02,P}$$

where:

$E_{18,P}$ = the emissions from a process in 2018
D = the forecast development of process p in the area
$E_{02,P}$ = the state average emissions from process p in 2002

Counties where this method was applied were first identified when the intersection of the RMP areas with counties resulted in the assignment of 2018 RMP-predicted oil, gas, CBM and/or drilled wells to a county that had no such wells in 2002. This number of 2018 oil, gas, CBM and/or drilled wells served as the activity measure for the 2018 emissions estimates. State specific emission factors were derived by dividing 2002 state total process-specific emissions by the number of 2002 oil, gas or drilled wells. In the case of CBM wells, the lack of 2002 emissions in some states required that an emission factor be adopted from another area. In these cases, data from the State of Wyoming were adopted. The emission factors that resulted for NOx are shown in Table 4-8. Emission factors for other pollutants were developed by the same approach.

Table 4-8. State NOx emission factors used to estimate 2018 emissions.

Process	Drill Rigs	Compressor Engines	Oil Well Heaters	Gas Well Heaters	Gas Well Completion Flaring & Venting	CBM Pump Engines
Derivation	Drill Rig Emissions/ Wells Drilled	Compressor Emissions/ Gas Produced	Oil Well Heater Emissions /Oil Wells	Gas Well Heater Emissions/ Gas Wells	Gas Well Completion Emissions/ Gas Wells	CBM Emissions/ CBM Wells
Units	tons/well drilled	tons/MCF	tons/well	tons/well	tons/well	tons/well
Montana	2.26	2.34×10^{-5}	0.011	0.859	0.147	0.12
New Mexico	7.12	2.34×10^{-5}	0.008	0.868	0.046	0.12
North Dakota	9.78	2.34×10^{-5}		0.867	0.031	0.12
Utah	5.37	4.11×10^{-6}	0.015			0.12

The emission factors in Table 4-8 were combined with development forecasts as shown in Calculation 4 to produce the county-level emissions shown in Table 4-9. These emissions estimates were then combined with the projected 2018 emissions to produce a comprehensive 2018 area source oil and gas emission inventory.

Table 4-9. 2018 emissions estimates for counties with no 2002 emissions.

State	County	Drill Rigs	Compressor Engines	Wellhead	CBM Pump Engines
Montana	Big Horn	720.45	7,754.11	35.00	119.81
	Golden Valley	7.23	-	-	-
	Mussellshell	124.73	22.42	64.46	-
	Powder River	720.45	7,740.31	-	119.81
	Yellowstone	50.61	10.45	26.49	-
New Mexico	McKinley	67.83	-	-	-
	Otero	9.22	26.74	12.02	-
	Sandoval	35.05	-	-	-
	Sierra	13.83	28.44	12.94	-
North Dakota	Billings	137.76	799.48	213.00	0.15
	Dunn	-	13.70	1.15	0.15
	Golden Valley	8.54	58.42	13.20	0.15
	Slope	7.43	52.03	11.48	0.15
Utah	Daggett	6.21	0.55	0.13	-
	Duschene	-	14.40	-	1.27
	Total	1,909.34	16,521.05	389.87	241.47

Future Year Emission Controls

Implementation of new federal and state control programs will have a substantial impact on future emissions. Known State and Federal emissions control estimates were incorporated into the base case projections for 2018. A summary of the controls that have been identified and the actions taken to incorporate them into the 2018 projections is provided in Table 4-10. These controls add to those previously identified in the 2002 inventory. Thus, although not presented here, the state-specific controls included in the 2002 inventory are adopted by the 2018 inventory. A discussion of the controls identified by the 2002 inventory is provided in Section 2.

Table 4-10. Projection information provided by State DEQ.

State	Future Controls	Action
All	Nonroad diesel engine standards (EPA, 2004)	Used phase-in and emissions standards information for 750+ hp drill rig engines from EPA's NONROAD model to adjust drill rig engine emissions for future performance standards
All	Nonroad spark-ignition engine standards (EPA, 2004)	Used phase-in and emissions standards information for natural gas fired nonroad engines (SCC 2268000000) from EPA's NONROAD model to adjust CBM pump engine emissions for future performance standards

State	Future Controls	Action
Colorado[1]	• 2004, control for glycol dehydrators requiring units in the nonattainment area with greater than 15 tpy VOC emission to achieve 90% control. • 2006, new control of large engines in the Denver-Joulsbourgh Basin NA Area • 2006, new control on condensate tanks requiring VOC emissions in nonattainment area reduced by 47.5% during the VOC season and 38% during off season (CDPHE, 2005)	The following was used as inputs to the procedure used to project point sources: • Determine fraction of dehydrators in nonattainment area and for 2004 and beyond apply 90% control to that fraction. • Select engines with greater than 500 hp and apply 90% control for 2006 and beyond. • Reduce annual VOC emissions from condensate tanks by 43% for 2006 and beyond.
Montana	2006, allow producers to include controls in their potential to emit estimates so that they can stay under 25 tpy and thus not be permitted. DEQ regulation will probably be introduced to require controlling PTE to 25 tpy (MT DEQ, 2005)	No action taken because control requirement has not been promulgated.
Utah	Controls under development with EPA Region 8 (UT DEQ, 2005)	No action taken because control requirements have not been promulgated.

[1]In Colorado, due to the low point source inventory threshold, these control adjustments have been made in the point source inventory

With the exception of the rules imposed in the State of Colorado, the future year controls reported by States were not certain to be implemented and their potential impact was uncertain. In other words, only "on-the-books" controls have been accounted for in this inventory. Due to the low inventory threshold in the State of Colorado, those state-level controls were incorporated in the point source inventory. That left only the federal nonroad engine performance standards to incorporate in this inventory.

After discussion with members of the oil and gas working group, it was determined that the nonroad engine performance standards were applicable to drill rig engines and CBM pump engines, but not to compressor engines. The compressor engine 2018 emissions assume future compressor engines are therefore not required to meet federal nonroad engine standards. In contrast, the 2018 drill rig and CBM pump emissions were adjusted downward under the assumption that future equipment purchases will be required to meet the federal nonroad engine standards. The adjustment for drill rig emissions was performed by comparing the emission rates yielded by EPA's NONROAD model for 750+ horsepower drill rig engines in 2018 versus those for the same category in 2002. For CBM pump engines, the adjustment was performed by comparing the emission rates given by the NONROAD model for natural gas fired engines in 2018 versus those for the same category in 2002. These comparisons were performed on a county level for all WRAP counties and control factors were derived for each county as the 2018 emission rates divided by the 2002 emission rates. The county-level controlled 2018 emissions were then calculated as the product of the county control factor and the uncontrolled 2018 emissions estimate. The emission summaries presented at the beginning of this section represent the comprehensive 2018 oil and gas emissions estimates with "on-the-books" controls.

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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/completion**
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
Benzene = 31.4 lb per yr/BPD
Toluene = 0.8 lb per yr/BPD
Ethyl benzene = 2.6 lb per yr/BPD
Xylenes = 1.8 lb per yr/BPD
n-Hexane = 7.8 lb per yr/BPD

Controlled
Benzene = 0.63 lb per yr/BPD
Toluene = 0.02 lb per yr/BPD
Ethyl benzene = 0.05 lb per yr/BPD
Xylenes = 0.04 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

Appendix D

2002 to 2018 Oil and Gas Growth Factors

SCC	FIPS	Growth Factor
2310000220	00000	4.4368
2310000220	02020	0.0000
2310000220	02122	1.0000
2310000220	02185	1.0000
2310000220	08001	1.0710
2310000220	08007	1.0580
2310000220	08009	1.0710
2310000220	08014	1.0710
2310000220	08017	1.0710
2310000220	08045	1.0614
2310000220	08051	1.0710
2310000220	08055	1.0710
2310000220	08057	1.0710
2310000220	08061	1.0710
2310000220	08067	1.1138
2310000220	08071	1.0710
2310000220	08073	1.0710
2310000220	08075	1.0710
2310000220	08077	1.0710
2310000220	08081	1.0582
2310000220	08083	1.0710
2310000220	08087	1.0710
2310000220	08099	1.0710
2310000220	08103	1.5108
2310000220	08107	1.0710
2310000220	08113	1.0710
2310000220	08121	1.0710
2310000220	08123	1.0710
2310000220	08125	1.0710
2310000220	30003	39.4556
2310000220	30005	0.1202
2310000220	30009	129.8828
2310000220	30011	1.0710
2310000220	30015	1.0710
2310000220	30017	8.2123
2310000220	30019	1.0710
2310000220	30021	1.0710
2310000220	30025	1.0710
2310000220	30027	1.0710
2310000220	30035	1.0710
2310000220	30041	1.0710
2310000220	30045	1.0710

SCC	FIPS	Growth Factor
2310000220	30051	1.0710
2310000220	30055	1.0710
2310000220	30065	85.3516
2310000220	30069	1.0710
2310000220	30071	1.0710
2310000220	30073	1.0710
2310000220	30075	76.3745
2310000220	30079	1.0710
2310000220	30083	1.0710
2310000220	30085	1.0710
2310000220	30087	1.0710
2310000220	30091	1.0710
2310000220	30095	12.3698
2310000220	30097	2.4740
2310000220	30101	1.0710
2310000220	30105	1.0710
2310000220	30111	34.6354
2310000220	32007	1.0710
2310000220	32011	1.0710
2310000220	32023	1.0710
2310000220	35005	1.0710
2310000220	35007	1.0710
2310000220	35015	1.0710
2310000220	35025	1.0710
2310000220	35039	2.6956
2310000220	35041	1.0710
2310000220	35045	2.6596
2310000220	35059	1.0710
2310000220	38007	2.8811
2310000220	38009	1.0710
2310000220	38011	1.0710
2310000220	38013	1.0710
2310000220	38023	1.0710
2310000220	38025	1.0889
2310000220	38033	0.9604
2310000220	38035	1.0710
2310000220	38049	1.0710
2310000220	38053	2.1276
2310000220	38059	1.0710
2310000220	38075	1.0710
2310000220	38087	0.1172
2310000220	38089	1.0710
2310000220	38093	1.0710
2310000220	38103	1.0710
2310000220	38105	1.0710

SCC	FIPS	Growth Factor
2310000220	46047	1.0710
2310000220	46063	1.0710
2310000220	49007	1.0710
2310000220	49013	5.1715
2310000220	49015	1.0710
2310000220	49019	1.0710
2310000220	49037	1.0710
2310000220	49047	8.7089
2310000220	56001	1.0710
2310000220	56003	1.0710
2310000220	56005	2.2528
2310000220	56007	1.1995
2310000220	56009	24.1974
2310000220	56011	1.0710
2310000220	56013	1.0710
2310000220	56017	1.0710
2310000220	56019	0.7792
2310000220	56023	1.3425
2310000220	56025	1.0710
2310000220	56027	1.0710
2310000220	56029	1.0710
2310000220	56033	1.5976
2310000220	56035	3.8028
2310000220	56037	1.1577
2310000220	56041	1.0710
2310010100	00000	1.2753
2310010100	08001	1.3340
2310010100	08005	1.3340
2310010100	08007	1.0022
2310010100	08009	1.3340
2310010100	08013	1.3340
2310010100	08017	1.3340
2310010100	08033	1.3340
2310010100	08039	1.3340
2310010100	08043	1.3340
2310010100	08045	1.3300
2310010100	08057	1.3340
2310010100	08061	1.3340
2310010100	08063	1.3340
2310010100	08067	1.3307
2310010100	08069	1.3340
2310010100	08073	1.3340
2310010100	08075	1.3340
2310010100	08077	1.3340
2310010100	08081	1.3253

SCC	FIPS	Growth Factor
2310010100	08083	1.3340
2310010100	08087	1.3340
2310010100	08099	1.3340
2310010100	08103	0.9979
2310010100	08107	1.3340
2310010100	08113	1.3340
2310010100	08115	1.3340
2310010100	08121	1.3340
2310010100	08123	1.3340
2310010100	30003	0.9649
2310010100	30005	0.9899
2310010100	30009	0.9746
2310010100	30019	1.3340
2310010100	30021	1.3340
2310010100	30025	1.3340
2310010100	30033	1.3340
2310010100	30035	1.3340
2310010100	30041	1.3340
2310010100	30051	1.3340
2310010100	30055	1.3340
2310010100	30065	0.9227
2310010100	30069	1.3340
2310010100	30073	1.3340
2310010100	30075	1.0000
2310010100	30079	1.3340
2310010100	30083	1.3340
2310010100	30085	1.3340
2310010100	30087	1.3340
2310010100	30091	1.3340
2310010100	30095	0.8333
2310010100	30099	1.3340
2310010100	30101	1.3340
2310010100	30105	1.3340
2310010100	30109	1.3340
2310010100	30111	1.0000
2310010100	32011	1.3340
2310010100	32023	1.3340
2310010100	35005	0.8660
2310010100	35015	0.8660
2310010100	35025	0.8660
2310010100	35031	0.9953
2310010100	35039	1.2786
2310010100	35041	0.8660
2310010100	35043	1.0263
2310010100	35045	1.7402

SCC	FIPS	Growth Factor
2310010100	38007	1.0336
2310010100	38009	1.3340
2310010100	38011	1.3340
2310010100	38013	1.3340
2310010100	38023	1.3340
2310010100	38025	1.3268
2310010100	38033	1.1452
2310010100	38041	1.3340
2310010100	38049	1.3340
2310010100	38053	1.1667
2310010100	38055	1.3340
2310010100	38061	1.3340
2310010100	38075	1.3340
2310010100	38087	0.9789
2310010100	38089	1.3340
2310010100	38101	1.3340
2310010100	38105	1.3340
2310010100	46041	1.3340
2310010100	46047	1.3340
2310010100	46063	1.3340
2310010100	49013	1.6365
2310010100	49015	1.3340
2310010100	49017	1.3340
2310010100	49019	1.3340
2310010100	49037	1.3340
2310010100	49043	1.3340
2310010100	49047	3.8530
2310010100	56001	1.3340
2310010100	56003	1.3340
2310010100	56005	0.9965
2310010100	56007	1.2974
2310010100	56009	1.0727
2310010100	56011	1.3340
2310010100	56013	1.3340
2310010100	56017	1.3340
2310010100	56019	0.9771
2310010100	56021	1.3340
2310010100	56023	1.3285
2310010100	56025	1.3340
2310010100	56027	1.3340
2310010100	56029	1.3340
2310010100	56033	0.9994
2310010100	56035	0.9955
2310010100	56037	1.3158
2310010100	56041	1.3340

SCC	FIPS	Growth Factor
2310010100	56043	1.3340
2310010100	56045	1.3340
2310010200	00000	1.2753
2310010200	08001	1.3340
2310010200	08005	1.3340
2310010200	08007	1.0022
2310010200	08009	1.3340
2310010200	08013	1.3340
2310010200	08017	1.3340
2310010200	08033	1.3340
2310010200	08039	1.3340
2310010200	08043	1.3340
2310010200	08045	1.3300
2310010200	08057	1.3340
2310010200	08061	1.3340
2310010200	08063	1.3340
2310010200	08067	1.3307
2310010200	08069	1.3340
2310010200	08073	1.3340
2310010200	08075	1.3340
2310010200	08077	1.3340
2310010200	08081	1.3253
2310010200	08083	1.3340
2310010200	08087	1.3340
2310010200	08099	1.3340
2310010200	08103	0.9979
2310010200	08107	1.3340
2310010200	08113	1.3340
2310010200	08115	1.3340
2310010200	08121	1.3340
2310010200	08123	1.3340
2310010200	30003	0.9649
2310010200	30005	0.9899
2310010200	30009	0.9746
2310010200	30019	1.3340
2310010200	30021	1.3340
2310010200	30025	1.3340
2310010200	30033	1.3340
2310010200	30035	1.3340
2310010200	30041	1.3340
2310010200	30051	1.3340
2310010200	30055	1.3340
2310010200	30065	0.9227
2310010200	30069	1.3340
2310010200	30073	1.3340

SCC	FIPS	Growth Factor
2310010200	30075	1.0000
2310010200	30079	1.3340
2310010200	30083	1.3340
2310010200	30085	1.3340
2310010200	30087	1.3340
2310010200	30091	1.3340
2310010200	30095	0.8333
2310010200	30099	1.3340
2310010200	30101	1.3340
2310010200	30105	1.3340
2310010200	30109	1.3340
2310010200	30111	1.0000
2310010200	32011	1.3340
2310010200	32023	1.3340
2310010200	35005	0.8660
2310010200	35015	0.8660
2310010200	35025	0.8660
2310010200	35031	0.9953
2310010200	35039	1.2786
2310010200	35041	0.8660
2310010200	35043	1.0263
2310010200	35045	1.7402
2310010200	38007	1.0336
2310010200	38009	1.3340
2310010200	38011	1.3340
2310010200	38013	1.3340
2310010200	38023	1.3340
2310010200	38025	1.3268
2310010200	38033	1.1452
2310010200	38041	1.3340
2310010200	38049	1.3340
2310010200	38053	1.1667
2310010200	38055	1.3340
2310010200	38061	1.3340
2310010200	38075	1.3340
2310010200	38087	0.9789
2310010200	38089	1.3340
2310010200	38101	1.3340
2310010200	38105	1.3340
2310010200	46041	1.3340
2310010200	46047	1.3340
2310010200	46063	1.3340
2310010200	49013	1.6365
2310010200	49015	1.3340
2310010200	49017	1.3340

SCC	FIPS	Growth Factor
2310010200	49019	1.3340
2310010200	49037	1.3340
2310010200	49043	1.3340
2310010200	49047	3.8530
2310010200	56001	1.3340
2310010200	56003	1.3340
2310010200	56005	0.9965
2310010200	56007	1.2974
2310010200	56009	1.0727
2310010200	56011	1.3340
2310010200	56013	1.3340
2310010200	56017	1.3340
2310010200	56019	0.9771
2310010200	56021	1.3340
2310010200	56023	1.3285
2310010200	56025	1.3340
2310010200	56027	1.3340
2310010200	56029	1.3340
2310010200	56033	0.9994
2310010200	56035	0.9955
2310010200	56037	1.3158
2310010200	56041	1.3340
2310010200	56043	1.3340
2310010200	56045	1.3340
2310010300	00000	1.2753
2310010300	08001	1.3340
2310010300	08005	1.3340
2310010300	08007	1.0022
2310010300	08009	1.3340
2310010300	08013	1.3340
2310010300	08017	1.3340
2310010300	08033	1.3340
2310010300	08039	1.3340
2310010300	08043	1.3340
2310010300	08045	1.3300
2310010300	08057	1.3340
2310010300	08061	1.3340
2310010300	08063	1.3340
2310010300	08067	1.3307
2310010300	08069	1.3340
2310010300	08073	1.3340
2310010300	08075	1.3340
2310010300	08077	1.3340
2310010300	08081	1.3253
2310010300	08083	1.3340

SCC	FIPS	Growth Factor
2310010300	08087	1.3340
2310010300	08099	1.3340
2310010300	08103	0.9979
2310010300	08107	1.3340
2310010300	08113	1.3340
2310010300	08115	1.3340
2310010300	08121	1.3340
2310010300	08123	1.3340
2310010300	30003	0.9649
2310010300	30005	0.9899
2310010300	30009	0.9746
2310010300	30019	1.3340
2310010300	30021	1.3340
2310010300	30025	1.3340
2310010300	30033	1.3340
2310010300	30035	1.3340
2310010300	30041	1.3340
2310010300	30051	1.3340
2310010300	30055	1.3340
2310010300	30065	0.9227
2310010300	30069	1.3340
2310010300	30073	1.3340
2310010300	30075	1.0000
2310010300	30079	1.3340
2310010300	30083	1.3340
2310010300	30085	1.3340
2310010300	30087	1.3340
2310010300	30091	1.3340
2310010300	30095	0.8333
2310010300	30099	1.3340
2310010300	30101	1.3340
2310010300	30105	1.3340
2310010300	30109	1.3340
2310010300	30111	1.0000
2310010300	32011	1.3340
2310010300	32023	1.3340
2310010300	35005	0.8660
2310010300	35015	0.8660
2310010300	35025	0.8660
2310010300	35031	0.9953
2310010300	35039	1.2786
2310010300	35041	0.8660
2310010300	35043	1.0263
2310010300	35045	1.7402
2310010300	38007	1.0336

SCC	FIPS	Growth Factor
2310010300	38009	1.3340
2310010300	38011	1.3340
2310010300	38013	1.3340
2310010300	38023	1.3340
2310010300	38025	1.3268
2310010300	38033	1.1452
2310010300	38041	1.3340
2310010300	38049	1.3340
2310010300	38053	1.1667
2310010300	38055	1.3340
2310010300	38061	1.3340
2310010300	38075	1.3340
2310010300	38087	0.9789
2310010300	38089	1.3340
2310010300	38101	1.3340
2310010300	38105	1.3340
2310010300	46041	1.3340
2310010300	46047	1.3340
2310010300	46063	1.3340
2310010300	49013	1.6365
2310010300	49015	1.3340
2310010300	49017	1.3340
2310010300	49019	1.3340
2310010300	49037	1.3340
2310010300	49043	1.3340
2310010300	49047	3.8530
2310010300	56001	1.3340
2310010300	56003	1.3340
2310010300	56005	0.9965
2310010300	56007	1.2974
2310010300	56009	1.0727
2310010300	56011	1.3340
2310010300	56013	1.3340
2310010300	56017	1.3340
2310010300	56019	0.9771
2310010300	56021	1.3340
2310010300	56023	1.3285
2310010300	56025	1.3340
2310010300	56027	1.3340
2310010300	56029	1.3340
2310010300	56033	0.9994
2310010300	56035	0.9955
2310010300	56037	1.3158
2310010300	56041	1.3340
2310010300	56043	1.3340

SCC	FIPS	Growth Factor
2310010300	56045	1.3340
2310020600	00000	2.1729
2310020600	30003	
2310020600	30005	1.2437
2310020600	30009	2.8663
2310020600	30015	1.4580
2310020600	30017	12.9403
2310020600	30019	1.4580
2310020600	30021	1.4580
2310020600	30025	1.4580
2310020600	30027	1.4580
2310020600	30033	1.4580
2310020600	30035	1.4580
2310020600	30037	1.9294
2310020600	30041	1.4580
2310020600	30051	1.4580
2310020600	30065	0.9227
2310020600	30069	1.4580
2310020600	30071	1.4580
2310020600	30073	1.4580
2310020600	30075	311.8023
2310020600	30079	1.4580
2310020600	30083	1.4580
2310020600	30085	1.4580
2310020600	30087	1.4580
2310020600	30091	1.4580
2310020600	30095	1.8116
2310020600	30097	1.7071
2310020600	30099	1.4580
2310020600	30101	1.4580
2310020600	30105	1.4580
2310020600	30109	1.4580
2310020600	32003	1.4580
2310020600	32023	1.4580
2310020600	35001	1.4580
2310020600	35005	1.3540
2310020600	35007	1.3540
2310020600	35015	1.3540
2310020600	35021	1.3540
2310020600	35025	1.3540
2310020600	35031	36.4321
2310020600	35039	2.9281
2310020600	35041	1.3540
2310020600	35043	1.2953
2310020600	35045	3.6832

SCC	FIPS	Growth Factor
2310020600	35059	1.3540
2310020600	38003	1.4580
2310020600	38007	1.0525
2310020600	38009	1.4580
2310020600	38011	1.4580
2310020600	38013	1.4580
2310020600	38015	1.4580
2310020600	38023	1.4580
2310020600	38025	1.4483
2310020600	38033	1.2043
2310020600	38049	1.4580
2310020600	38053	3.1848
2310020600	38055	1.4580
2310020600	38059	1.4580
2310020600	38061	1.4580
2310020600	38075	1.4580
2310020600	38077	1.4580
2310020600	38087	0.9789
2310020600	38089	1.4580
2310020600	38093	1.4580
2310020600	38101	1.4580
2310020600	38105	1.4580
2310020600	41009	0.5680
2310020600	41019	0.5680
2310020600	41041	0.5680
2310020600	41043	0.5680
2310020600	41047	0.5680
2310020600	46033	1.4580
2310020600	46041	1.4580
2310020600	46047	1.4580
2310020600	46063	1.4580
2310020600	49007	1.4580
2310020600	49009	2.1185
2310020600	49013	3.7360
2310020600	49015	1.4580
2310020600	49017	1.4580
2310020600	49019	1.4580
2310020600	49037	1.4580
2310020600	49043	1.4580
2310020600	49047	2.6255
2310020600	56001	1.4580
2310020600	56003	1.4580
2310020600	56005	7.1804
2310020600	56007	1.6387
2310020600	56009	1.1066

SCC	FIPS	Growth Factor
2310020600	56011	1.4580
2310020600	56013	1.4580
2310020600	56017	1.4580
2310020600	56019	6.9460
2310020600	56021	1.4580
2310020600	56023	1.5406
2310020600	56025	1.4580
2310020600	56027	1.4580
2310020600	56029	1.4580
2310020600	56033	7.6748
2310020600	56035	7.4527
2310020600	56037	1.5236
2310020600	56041	1.4580
2310020600	56043	1.4580
2310020600	56045	1.4580
2310021100	00000	2.3099
2310021100	08001	1.4580
2310021100	08005	1.4580
2310021100	08007	1.0177
2310021100	08009	1.4580
2310021100	08011	1.4580
2310021100	08013	1.4580
2310021100	08014	1.4580
2310021100	08017	1.4580
2310021100	08029	1.4580
2310021100	08031	1.4580
2310021100	08033	1.4580
2310021100	08039	1.4580
2310021100	08045	1.4595
2310021100	08051	1.4580
2310021100	08055	1.4580
2310021100	08057	1.4580
2310021100	08061	1.4580
2310021100	08063	1.4580
2310021100	08067	1.4535
2310021100	08069	1.4580
2310021100	08071	1.4580
2310021100	08073	1.4580
2310021100	08075	1.4580
2310021100	08077	1.4580
2310021100	08081	1.4638
2310021100	08083	1.4580
2310021100	08087	1.4580
2310021100	08095	1.4580
2310021100	08099	1.4580
2310021100	08103	1.6764
2310021100	08107	1.4580
2310021100	08113	1.4580
2310021100	08121	1.4580
2310021100	08123	1.4580
2310021100	08125	1.4580
2310021100	30005	1.2437
2310021100	30009	3.6853
2310021100	30015	1.4580
2310021100	30017	12.9403
2310021100	30025	1.4580
2310021100	30027	1.4580
2310021100	30035	1.4580
2310021100	30037	1.9294
2310021100	30041	1.4580
2310021100	30051	1.4580
2310021100	30071	1.4580
2310021100	30073	1.4580
2310021100	30075	371.1493
2310021100	30079	1.4580
2310021100	30083	1.4580
2310021100	30085	1.4580
2310021100	30091	1.4580
2310021100	30095	1.8116
2310021100	30097	1.7071
2310021100	30099	1.4580
2310021100	30101	1.4580
2310021100	30105	1.4580
2310021100	30109	1.4580
2310021100	32023	1.4580
2310021100	35001	1.4580
2310021100	35005	1.3540
2310021100	35007	1.3540
2310021100	35015	1.3540
2310021100	35021	1.3540
2310021100	35025	1.3540
2310021100	35031	36.4321
2310021100	35039	2.9921
2310021100	35041	1.3540
2310021100	35043	1.4274
2310021100	35045	3.7217
2310021100	35059	1.3540
2310021100	38011	1.4580
2310021100	38013	1.4580
2310021100	38053	5.9557
2310021100	38105	1.4580
2310021100	41009	0.5680
2310021100	46063	1.4580
2310021100	49007	1.4580
2310021100	49009	2.1185
2310021100	49013	116.0424
2310021100	49015	1.4580
2310021100	49019	1.4580
2310021100	49037	1.4580
2310021100	49043	1.4580
2310021100	49047	2.5806
2310021100	56001	1.4580
2310021100	56003	1.4580
2310021100	56005	0.9965
2310021100	56007	1.6616
2310021100	56009	1.1075
2310021100	56011	1.4580
2310021100	56013	1.4580
2310021100	56017	1.4580
2310021100	56019	0.9771
2310021100	56023	1.5411
2310021100	56025	1.4580
2310021100	56027	1.4580
2310021100	56029	1.4580
2310021100	56035	7.4972
2310021100	56037	1.5467
2310021100	56041	1.4580
2310021100	56043	1.4580
2310021100	56045	1.4580
2310021300	00000	2.3099
2310021300	08001	1.4580
2310021300	08005	1.4580
2310021300	08007	1.0177
2310021300	08009	1.4580
2310021300	08011	1.4580
2310021300	08013	1.4580
2310021300	08014	1.4580
2310021300	08017	1.4580
2310021300	08029	1.4580
2310021300	08031	1.4580
2310021300	08033	1.4580
2310021300	08039	1.4580
2310021300	08045	1.4595
2310021300	08051	1.4580
2310021300	08055	1.4580

SCC	FIPS	Growth Factor	SCC	FIPS	Growth Factor	SCC	FIPS	Growth Factor
2310021300	08057	1.4580	2310021300	35005	1.3540	2310021400	35001	1.4580
2310021300	08061	1.4580	2310021300	35007	1.3540	2310021400	35005	1.3540
2310021300	08063	1.4580	2310021300	35015	1.3540	2310021400	35007	1.3540
2310021300	08067	1.4535	2310021300	35021	1.3540	2310021400	35015	1.3540
2310021300	08069	1.4580	2310021300	35025	1.3540	2310021400	35021	1.3540
2310021300	08071	1.4580	2310021300	35031	36.4321	2310021400	35025	1.3540
2310021300	08073	1.4580	2310021300	35039	2.9921	2310021400	35031	36.4321
2310021300	08075	1.4580	2310021300	35041	1.3540	2310021400	35039	2.9921
2310021300	08077	1.4580	2310021300	35043	1.4274	2310021400	35041	1.3540
2310021300	08081	1.4638	2310021300	35045	3.7217	2310021400	35043	1.4274
2310021300	08083	1.4580	2310021300	35059	1.3540	2310021400	35045	3.7217
2310021300	08087	1.4580	2310021300	38011	1.4580	2310021400	35059	1.3540
2310021300	08095	1.4580	2310021300	38013	1.4580	2310021400	38011	1.4580
2310021300	08099	1.4580	2310021300	38053	5.9557	2310021400	38013	1.4580
2310021300	08103	1.6764	2310021300	38105	1.4580	2310021400	38053	5.9557
2310021300	08107	1.4580	2310021300	41009	0.5680	2310021400	38105	1.4580
2310021300	08113	1.4580	2310021300	46063	1.4580	2310021400	41009	0.5680
2310021300	08121	1.4580	2310021300	49007	1.4580	2310021400	46063	1.4580
2310021300	08123	1.4580	2310021300	49009	2.1185	2310021400	49007	1.4580
2310021300	08125	1.4580	2310021300	49013	116.0424	2310021400	49009	2.1185
2310021300	30005	1.2437	2310021300	49015	1.4580	2310021400	49013	116.0424
2310021300	30009	3.6853	2310021300	49019	1.4580	2310021400	49015	1.4580
2310021300	30015	1.4580	2310021300	49037	1.4580	2310021400	49019	1.4580
2310021300	30017	12.9403	2310021300	49043	1.4580	2310021400	49037	1.4580
2310021300	30025	1.4580	2310021300	49047	2.5806	2310021400	49043	1.4580
2310021300	30027	1.4580	2310021300	56001	1.4580	2310021400	49047	2.5806
2310021300	30035	1.4580	2310021300	56003	1.4580	2310021400	56001	1.4580
2310021300	30037	1.9294	2310021300	56005	0.9965	2310021400	56003	1.4580
2310021300	30041	1.4580	2310021300	56007	1.6616	2310021400	56005	0.9965
2310021300	30051	1.4580	2310021300	56009	1.1075	2310021400	56007	1.6616
2310021300	30071	1.4580	2310021300	56011	1.4580	2310021400	56009	1.1075
2310021300	30073	1.4580	2310021300	56013	1.4580	2310021400	56011	1.4580
2310021300	30075	371.1493	2310021300	56017	1.4580	2310021400	56013	1.4580
2310021300	30079	1.4580	2310021300	56019	0.9771	2310021400	56017	1.4580
2310021300	30083	1.4580	2310021300	56023	1.5411	2310021400	56019	0.9771
2310021300	30085	1.4580	2310021300	56025	1.4580	2310021400	56023	1.5411
2310021300	30091	1.4580	2310021300	56027	1.4580	2310021400	56025	1.4580
2310021300	30095	1.8116	2310021300	56029	1.4580	2310021400	56027	1.4580
2310021300	30097	1.7071	2310021300	56035	7.4972	2310021400	56029	1.4580
2310021300	30099	1.4580	2310021300	56037	1.5467	2310021400	56035	7.4972
2310021300	30101	1.4580	2310021300	56041	1.4580	2310021400	56037	1.5467
2310021300	30105	1.4580	2310021300	56043	1.4580	2310021400	56041	1.4580
2310021300	30109	1.4580	2310021300	56045	1.4580	2310021400	56043	1.4580
2310021300	32023	1.4580	2310021400	00000	2.3099	2310021400	56045	1.4580
2310021300	35001	1.4580	2310021400	32023	1.4580	2310021500	00000	2.3099

SCC	FIPS	Growth Factor
2310021500	02122	0.2138
2310021500	08001	1.4580
2310021500	08009	1.4580
2310021500	08013	1.4580
2310021500	08014	1.4580
2310021500	08017	1.4580
2310021500	08045	1.4595
2310021500	08067	1.4535
2310021500	08071	1.4580
2310021500	08073	1.4580
2310021500	08075	1.4580
2310021500	08077	1.4580
2310021500	08081	1.4638
2310021500	08087	1.4580
2310021500	08099	1.4580
2310021500	08103	1.6764
2310021500	08113	1.4580
2310021500	08121	1.4580
2310021500	08123	1.4580
2310021500	08125	1.4580
2310021500	30005	1.2437
2310021500	30015	1.4580
2310021500	30025	1.4580
2310021500	30041	1.4580
2310021500	30051	1.4580
2310021500	30071	1.4580
2310021500	30101	1.4580
2310021500	30105	1.4580
2310021500	35001	1.4580
2310021500	35005	1.3540
2310021500	35007	1.3540
2310021500	35015	1.3540
2310021500	35025	1.3540
2310021500	35039	2.9921
2310021500	35045	3.7217
2310021500	35059	1.3540
2310021500	38011	1.4580
2310021500	49007	1.4580
2310021500	49043	1.4580
2310021500	49047	2.5806
2310021500	56003	1.4580
2310021500	56005	0.9965
2310021500	56007	1.6616
2310021500	56013	1.4580
2310021500	56023	1.5411

SCC	FIPS	Growth Factor
2310021500	56025	1.4580
2310021500	56029	1.4580
2310021500	56035	7.4972
2310021500	56037	1.5467
2310021500	56041	1.4580
2310023000	00000	1.6924
2310023000	08007	1.4580
2310023000	08045	1.4580
2310023000	08055	1.4580
2310023000	08067	1.5838
2310023000	08071	1.4580
2310023000	08077	1.4580
2310023000	08081	1.4580
2310023000	08103	0.9955
2310023000	08107	1.4580
2310023000	35007	0.0000
2310023000	35039	1.9105
2310023000	35045	1.9162
2310023000	56005	7.6917
2310023000	56007	1.4580
2310023000	56009	7.6666
2310023000	56019	7.6901
2310023000	56033	7.6748
2310023000	56035	0.9926
2310023000	56037	1.4580
2310023000	56041	1.4580
2310030210	00000	2.3099
2310030210	35001	1.4580
2310030210	35005	1.3540
2310030210	35015	1.3540
2310030210	35025	1.3540
2310030210	35039	2.9921
2310030210	35041	1.3540
2310030210	35043	1.4274
2310030210	35045	3.7217
2310030210	49007	1.4580
2310030210	49009	2.1185
2310030210	49013	116.0424
2310030210	49015	1.4580
2310030210	49019	1.4580
2310030210	49037	1.4580
2310030210	49043	1.4580
2310030210	49047	2.5806
2310030210	56003	1.4580
2310030210	56005	0.9965

SCC	FIPS	Growth Factor
2310030210	56007	1.6616
2310030210	56009	1.1075
2310030210	56013	1.4580
2310030210	56017	1.4580
2310030210	56023	1.5411
2310030210	56025	1.4580
2310030210	56027	1.4580
2310030210	56029	1.4580
2310030210	56035	7.4972
2310030210	56037	1.5467
2310030210	56041	1.4580
2310030210	56043	1.4580
2310030210	56045	1.4580
2310030220	30009	3.6853
2310030220	30035	1.4580
2310030220	30091	1.4580
2310030220	30101	1.4580
2310030220	38013	1.4580
2310030220	38053	5.9557
2310030220	38105	1.4580
2310030220	56005	0.9965
2310030220	56007	1.6616
2310030220	56009	1.1075
2310030220	56013	1.4580
2310030220	56023	1.5411
2310030220	56025	1.4580
2310030220	56027	1.4580
2310030220	56029	1.4580
2310030220	56035	7.4972
2310030220	56037	1.5467
2310030220	56041	1.4580
2310030220	56043	1.4580
2310030220	56045	1.4580