An Emission Inventory of Non-point Oil and Gas Emissions Sources in the Western Region

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ABSTRACT

As part of an effort undertaken by the Western Regional Air Partnership (WRAP) to consolidate and improve on the 2002 state and tribal emission inventories, ENVIRON developed an emission inventory of non-point emission sources associated with the production of oil and gas. This inventory focused on emissions of nitrous oxides from compressor engines, drill rig engines and coalbed methane pump engines. Methodologies were developed that could be applied consistently across the western region, without overlooking the variability in local production characteristics, control requirements and inventory thresholds. Application of these methodologies resulted in the addition of almost 120,000 tons of NOx emissions to the 2002 WRAP emission inventory. New spatial surrogates were generated based on well locations to appropriately distribute these emissions.

An oil and gas inventory for 2018 was estimated by growing the 2002 inventory using growth factors derived from resource management plans produced by the Bureau of Land Management and regional forecasts made by the Energy Information Administration. Additional effort was made to estimate emissions in new development areas without base year emissions. The resulting approach incorporated the most complete information available on the anticipated oil and gas development in the western region to produce an inventory that predicts a doubling of non-point oil and gas NOx emissions between 2002 and 2018. A complementary project recently completed by the authors in Northeast Texas has demonstrated a control technology for compressor engines with the potential to eliminate approximately 80 percent of the 2002 to 2018 growth in NOx emissions at cost of less than $200 per ton.

INTRODUCTION

Background

In 2002, more than 8.3 trillion cubic feet of natural gas and 820 million barrels of crude oil were drawn from oil and gas wells in the 14 western states[1,2]. To achieve this level of production, an extensive fleet of oil and gas production equipment operates continuously across the region. The sizes and types of equipment in that fleet vary from small chemical injection pumps up to gas turbines of several thousand horsepower. Despite their differences, at least one common feature unites many of these equipment types. They emit nitrous oxides (NOx), volatile organic compounds (VOC) and other air pollutants as part of their normal daily operations. Even the smallest of these source types may result in significant emissions when the continuous operation and the number of units are taken into consideration.

Previous emission inventories have addressed limited segments of the oil and gas production industry. In particular, large oil and gas facilities have been well accounted for in state point source inventories. Attempts have also been made to capture some of the smaller oil and gas sources in area source inventories. The 2002 emission inventories prepared by the State of Wyoming and the State of California include emissions for a number of smaller wellhead processes. Additional studies have made gains in characterizing oil and gas emissions in major development areas, such as the San Juan Basin and Jonah-Pinedale. These studies advanced the understanding of emissions from this industry, but the magnitude of emissions they uncovered also highlighted the absence of area source oil and gas emissions in the inventories of other states and production areas.

Objective and Approach

The methodologies and results presented in this paper are the synthesis of three separate studies to characterize emissions from the oil and gas production industry and to determine if future reductions of these emissions could make a significant contribution toward improved air quality. These three studies were as follows:

- **2002 and 2018 state oil and gas inventories prepared for the Stationary Sources Joint Forum (SSJF) of the Western Regional Air Partnership (WRAP)** – The WRAP-SSJF commissioned this study to develop and implement an emission inventory methodology for oil and gas sources in the 14 member states – Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, North Dakota, Oregon, South Dakota, Utah, Washington and Wyoming. This inventory adopted the oil and gas point source emissions from the existing state inventories and reconciled new oil and gas area source inventories with those existing point source emissions. Discussion of this inventory is limited to the development of county level area source oil and gas emissions estimates.

- **2002 and 2018 tribal oil and gas inventories prepared for the Tribal Data Development Work Group (TDDWG) of the WRAP –** In this study, oil and gas emission inventories were prepared for three tribes – the Arapahoe and Shoshone of the Wind River Reservation, the Navajo Nation and the Ute Mountain Ute. Emissions estimates were prepared using the inventory methodology developed for the WRAP-SSJF project, with adjustments to utilize the activity data available for each tribe.

- **Pilot project to evaluate the effectiveness of an emission control system for gas compressor engines conducted for Northeast Texas Air Care (NETAC) –** In 2004, NETAC commissioned a pilot project to demonstrate the effectiveness of available technology in reducing nitrogen oxide emissions from compressor engines used in gas production operations. This pilot project succeeded in retrofitting five gas compressor engines with controls that reduced NOx emissions from those engines by greater than 90 percent.

The discussion of these three projects in this paper is organized to focus on the major themes of the three studies – emission inventory development, future year emission projections and emission control strategies. As such, the development of the base year 2002 area source oil and gas inventories for the states and for the tribes is discussed in the first two sections of this paper. The third section describes the procedures used to project oil and gas emissions in the year 2018. This is followed by a brief discussion of the spatial allocation surrogates that were created to facilitate the modeling of those emissions. The final section then relates the results of the pilot project to evaluate an emission control technology for gas compressor engines.

WRAP - STATE OIL AND GAS INVENTORIES

The objective of this study was 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 on estimating emissions of pollutants with the potential to impair visibility near Class I areas in the west, in particular NOx emissions. Drill rigs, compressor engines and coalbed methane (CBM) pump engines were focused on because of their importance as NOx sources and the anticipated growth in the use of these equipment types as oil and gas development continues in the region. In addition, emissions were estimated for a number of sources collectively referred to as 'minor NOx and VOC sources' for which production-based emission factors had been developed.

Drill Rig Emissions

The approach developed to estimate emissions from drill rig engines used drill permit data from oil and gas commissions (OGCs) as a measure of activity and emission factors derived from a survey of drilling companies. The drill permit data found to be available from the state OGCs was 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 data 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. To translate that activity data to emissions estimates required the derivation of locally appropriate emission factors from a study of drilling emissions that was completed by the Wyoming Department of Environmental Quality[3].

The information provided by WY DEQ represented the synthesis of emissions estimates made by ten different drilling companies for a total of 218 wells drilled. The WY DEQ study yielded emission factors of 13.5 tons NOx and 3.3 tons SO_2 per well. However, because emissions from the drilling of a well are dependent upon the depth of the well, the composition of substrate and the characteristics of the rig engine(s), it was not appropriate to use the Jonah-Pinedale emission factors for all wells drilled in the WRAP States without some adjustment. We therefore developed a methodology that uses information about the characteristics of wells in a specific area to scale the Jonah-Pinedale emission factor to better represent drilling operations in that area.

The most local unit for which typical well characteristics were commonly available was the formation. To create emission factors for drilling in a given formation, it was necessary to make two important assumptions. First it was assumed that the difference between the completion date and the date that drilling ceased is, on average, constant relative to the total duration of well preparation activities. This assumption was needed because the actual date that drilling ceased was not available. It was also necessary to assume that the capacity of the equipment used to drill a well was 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. With those two assumptions, it was 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 average well depth and drilling duration for the formations drilled in Jonah-Pinedale - based on drill permit data obtained from the Wyoming OGC for 2002 and 2004 - was 11,896 ft and 80.6 days[4]. The same type of average well depth and drilling duration was 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*

Additional adjustments were considered beyond those for well depths and durations. State DEQs were surveyed to determine the control requirements for drill rigs. All state DEQs responded that controls were not required on drill rig engines. An adjustment was, however, necessary to account for the varying fuel sulfur levels between different states and counties. This adjustment 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.

Emissions for each formation were calculated as the product of the formation specific emission factor and the number of wells drilled in the formation in 2002. The emissions for that formation were then allocated to the counties that intersected the formation based on the fraction of the wells drilled that were drilled in each county's portion of the formation. The state total drill rig NOx and SO_2 emissions that resulted from this procedure are shown in Table 1. 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.

Table 1. State total drill rig emissions.

State	Wells Drilled	NOx (tons)	SO2 (tons)
Alaska	205	877	66
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

Non-Point Natural Gas Compressor Engine Emissions

The focus of this area source compressor engine emission estimate was the group of relatively small, dispersed wellhead compressor engines. In all but two of the natural gas producing states, these engines had not been included in previous emission inventories and their inclusion here represents a significant advance in understanding this important component of the gas production industry.

To estimate emissions from compressor engines, a production-based emission factor was developed from a local study of compressor engine emissions. This emission factor was 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 was evaluated, and ultimately, an industry-compiled inventory of wellhead compressor engines in the New Mexico portion of the San Juan Basin was selected.

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. 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[5]. 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. A total 2002 gas production of 1,030 BCF in those three counties was obtained from the online production database maintained by the New Mexico Institute of Mining and Technology[6]. 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.

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 online 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 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 per hp-hr[7,8]. This represents a substantial reduction from the average emission rate of 11.4 grams NOx/hp-hr that was found by the NMOGA Inventory. In both Utah and Wyoming, the controlled emission factor was calculated as the product of the uncontrolled emission factor and the ratio of controlled hourly emissions to uncontrolled hourly emissions, 2 grams NOx/hp-hr to 11.4 grams NOx/hp-hr. The state total NOx emissions that resulted from the application of these emission factors are presented in Table 2. As is shown in Table 2, the 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.

The State of Alaska and the State of Colorado represent two exceptions to this methodology. The State of Colorado included in its point source inventory all sources with actual 2002 emissions greater than 2 tons[9]. This is expected to include all compressor engines. In Alaska, personnel in the State's environmental department and the oil and gas conservation commission indicated that the equipment that channels oil and gas production to the large processing facilities is permitted along with the facility[10,11]. 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.

Table 2. 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

*California ARB provided separate estimates of area source oil and gas emissions

Coal Bed Methane Pump Engines

Five states in the western region produced coalbed methane in 2002 - Colorado, Montana, New Mexico, Utah and Wyoming. Contacts in the State of Montana and State of Utah environmental departments indicated that the CBM fields in their states are electrified and pumps are expected to be operated on line power[12,13]. Therefore it remained to determine emissions from CBM pump engines in only Colorado, New Mexico and Wyoming.

The only widely available indicator of pump engine activity that was identified was the water production at CBM wells. This data was obtained from the state OGCs. In addition, the depth of wells was obtained for many of the wells in each state, though it was not available for every well. 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 the water production. Once activity was estimated, it was then possible to derive an emission estimate using an emission factor from EPA's NONROAD emissions model[14].

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 is presented in Table 3.

Table 3. 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.	WY DEQ data shows that the majority of pump engine horsepower is natural gas fired[15]. Also, industry representatives indicate that use of electric power from the grid is minimal[16].
Pump efficiency = 0.6	Industry provided estimate[17].
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 conservative estimate.
Power delivered by the pump is exactly equal to the power required to lift water over the depth of the well and overcome frictional losses.	The power in lifting the water is undoubtedly much greater than any of the other components. No data was available on minor losses and exit velocity.
Diameter of pipe that conducts water to surface is 0.2 ft	Wyoming OGC provided estimate[18]
Pipe roughness of drawn/plastic tubing ($5x10^{-6}$ ft)	Industry contact stated majority of piping is fiberglass[19]
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[16].

Information from state OGC and industry contacts enabled us to define the relevant portions of the design of the average coal bed methane well. This system can be described using a simplified form of the Bernoulli equation, where the energy at the exit of the pipe is equal to the sum of the energy at the inlet plus the energy supplied by the pump and the frictional losses, as shown in Calculation 2.

Calculation 2. Modified Bernoulli equation

$$z_1 + H_P + H_L = z_2$$

where:

z = Elevation (1 = inlet of pipe, 2 = exit of pipe)
H_p = The head imparted by the pump (feet)
H_L = The head lost to friction (feet)

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, the flow becomes turbulent and there are several possible methods of estimating the frictional loss. In this study, we used the Hazen-Williams equation to estimate frictional losses for flowrates that implied a Reynolds Number above 3000.

Summing the frictional losses and adding that to the depth of the well estimated the energy imparted by the pump. Then, to determine the power of the pump we applied the equation shown in Calculation 3. Once the power delivered by the pump was calculated, determining the power developed by the engine was a matter of applying the assumed pump and generator efficiencies.

Calculation 3. 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)

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. The total engine activity was then the sum of 4,380 hours of engine activity while idling plus 4,380 hours of engine activity while pumping. Emissions were 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[14]. For Wyoming, an emission factor was developed to reflect the controls imposed 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 4. 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. These results are consistent with the statements of industry representatives indicating that the San Juan Basin, where most CBM production occurs in New Mexico, is a mature field where comparatively little dewatering is necessary[16].

Table 4. 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 Sources

In addition to the area sources identified as potentially major sources of NOx emissions, we estimated emissions for several other processes occurring at oil and gas wellheads. Emissions were estimated for both NOx and VOC using well-specific production as the activity indicator. The sources for which emissions were estimated in this portion of the inventory and the emission factors used are listed in Table 5. The default emission factors used for these sources were emission factors provided by the WY DEQ[20]. State agencies and industry were given the option of providing their own emission factors. Only the CDPHE provided alternate emission factors[9].

Table 5. VOC and minor NOx emission factors.

Gas Wells	Emission Factor	Oil Wells	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		

To use these emission factors, it was necessary to obtain well-specific production data from the state OGCs. In most cases, the necessary data was either compiled and submitted by the OGC or was downloaded from the OGC's website. The list of well-specific information obtained from the OGCs is presented in Table 6.

Table 6. Well-specific data obtained from the OGCs.

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

Having obtained well-specific data from all states, we divided those wells into oil and gas wells in order to apply the appropriate emission factors for each well type. From the list of gas wells that resulted we then eliminated the CBM wells, as WY DEQ stipulated that the emission factors provided for gas wells were applicable only to conventional gas wells. One additional filtering of the production data was 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 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 7. Both the controls reported by the CDPHE and WY DEQ are included in the emission factors provided by those agencies. The inclusion of controls in the Wyoming emission factors presented 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 7. 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

WY 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. Depending upon the specific control requirements in each state, the controlled and uncontrolled factors were applied to no wells, to some fraction of wells, or to all wells. Different control requirements were also applied to completion emissions across the region. A summary of the final, control-adjusted gas well emission factors used is presented in Table 8. The final oil well emission factors used are those presented in Table 5. These emission factors were combined with the well data to estimate emissions following the general procedure shown in Calculation 4.

Table 8. 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	
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
North Dakota	65	27,485	1,752	VOC = 86 NOx = 1.75	0.2
All Other States	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 4. 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

A summary of the emissions estimated for VOC and minor NOx processes is presented in Table 9. Emissions for condensate tanks and glycol dehydrators are not included for Colorado because those sources are included in the State's point source inventory[21]. Nor are emissions included for any process, except completion activities, in the State of Alaska. Emissions from the other VOC and minor NOx sources are expected to be included in the State's point source inventory because wellhead equipment is permitted under the umbrella of larger facilities[10,11]. Emissions were not estimated for glycol dehydrators in the State of Montana because it was reported that no wellhead dehydrators had been installed[22].

Table 9. State total emissions (tons) 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.

WRAP - TRIBAL OIL AND GAS INVENTORIES

At the same time as the oil and gas inventory improvement project was conducted for the WRAP States, a similar project was undertaken to estimate oil and gas emissions on tribal lands. Three tribal jurisdictions with oil and gas production on their lands participated in this project - the Arapahoe and Shoshone of the Wind River Reservation, the Navajo Nation and the Ute Mountain Ute. The methods employed to estimate emissions from oil and gas sources on tribal lands were based on those developed for the SSJF project. However, some aspects of the tribal inventories are distinct enough to warrant separate discussion.

Data Collection

The most significant way in which the tribal inventories differed from those prepared for the states was in the methods used to obtain activity data. Underlying all of the oil and gas emissions calculation methods is the availability of oil and gas production data and drill permit data. This information was publicly available in all of the WRAP States. The same was not true in the tribal jurisdictions. Among the three tribes worked with under this project, three differing levels of data availability were found. In each case a strategy was developed to fill the need for activity data with the information available in a manner that was acceptable to the tribe.

Arapahoe and Shoshone of the Wind River Reservation

The Wind River Environmental Quality Commission (WREQC) was worked with to obtain and validate drilling and oil and gas production data. The Shoshone Oil and Gas Commission (SOGC) was able to provide total 2002 oil and gas production for the fields on the Wind River Reservation, but not the well-specific production information used for many of the emissions estimates. When wells were selected from the WY OGC database using that same list of fields, the resulting wells had a total production within one percent of the production summaries provided by the SOGC[4,23]. Thus it was deemed acceptable to obtain the well-specific data required by selecting drill permits and well data from the WY OGC database for the fields on the Wind River Reservation. The WREQC confirmed the appropriateness of the final drilling and production activity[24]. This data is summarized in Table 10.

Table 10. Oil and gas activity data for the Wind River Reservation.

	Count	2002 Gas Production	2002 Oil/Condensate Production
Drilled Wells	21		
CBM Wells	0	0	
Gas Wells	212	28,184,154	242,400
Oil Wells	260	89,686	2,064,764

Navajo Nation

The Minerals Department of the Navajo Nation was contacted to obtain well production and drilling permit data. The Department referred us to the data maintained by the Bureau of Land Management (BLM) or the states, which the department believes to be accurate and uses for its own purposes[25]. Production and drilling data was obtained from the three states that intersect the Navajo Nation. The state data was analyzed to determine what portion of the data was applicable to operations on the Navajo Nation.

Well production and drill permits applicable to the Navajo Nation were selected from the total set of Arizona, Utah and New Mexico data using GIS software to plot the well and drill permit locations and then extract only those wells shown to be on the Navajo Nation. Plotting the locations of wells drilled revealed that only the New Mexico portion of the Navajo Nation was drilled in 2002. For each well drilled the necessary activity data was extracted from the New Mexico Oil Conservation Division database[26]. Using the same GIS analysis, oil and gas wells on the Navajo Nation were identified in the data of all three states. For those wells, the production data required for emissions estimates was extracted from the three state databases. The drilling and production data obtained for the Navajo Nation is summarized in Table 11.

Table 11. Oil and gas activity data for the Navajo Nation

	Count	2002 Gas Production	2002 Oil/Condensate Production	2002 Water Production
Drilled Wells	3			
CBM Wells	232	8,463,094		881,743
Gas Wells	523	11,230,764	40,926	
Oil Wells	798	4,457,537	5,121,230	

Maps of well locations created during this analysis and the production totals for oil and gas wells on the Navajo Nation were submitted to the Minerals Department for review. The Department responded that the map of well locations appeared to accurately depict oil and gas development on the Navajo Nation[25]. Also, the production figures developed were reported to be within the expected range for total production on the Navajo Nation[27].

Ute Mountain Ute

Efforts were made to obtain both drilling and production data from the Ute Mt Ute Energy Department, but the department provided only the names of the two production companies operating on the Ute Mountain Ute lands[28]. The drilling and production data was ultimately extracted from the databases of the Colorado Oil and Gas Conservation Commission and the NM OCD[29,26]. Wells on Ute Mt Ute lands were selected from the complete set of wells in New Mexico and Colorado using GIS software to plot the drill permit coordinates and then extract only those wells shown to be on the Ute Mt Ute lands.

The UMU Environmental Department provided 2002 oil and gas sales data collected by the UMU Department of Revenue to enable a check on the data extracted from the state databases[30]. The gas sales reported by the Department of Revenue proved much higher than was extracted from the state databases. Oil production was also slightly higher than that found in the state databases. To arrive at well specific production that summed to the figures reported by the Department of Revenue, oil and gas production at the wells extracted from the state databases was scaled up by the ratio of total oil/gas production from the state databases to total oil/gas production reported by the Department of Revenue. By this method, well specific oil and gas production was arrived at which, when summed, matched the total oil and gas sales reported by the Department of Revenue. A summary of the activity data compiled for the Ute Mountain Ute is shown in Table 12.

Table 12. Oil and gas activity data for the Ute Mountain Ute.

	Count	2002 Gas Production	2002 Oil/Condensate Production	2002 Water Production
Drilled Wells	1			
CBM Wells	0	0		0
Gas Wells	65	6,796,665	77,472	
Oil Wells	27	5,335	11,583	

One set of data gathered for the Ute Mountain Ute distinguishes the inventory for that tribe from all other state and tribal inventories. The two production companies identified by the Energy

Department were contacted to obtain activity data. What both companies provided was emissions for their compressor engine usage on the tribe's lands. The companies provided emissions data for compressor engine operations in 2005. This was scaled to estimate 2002 emissions based on the gas production in 2002 relative to 2005. Thus rather than using the standard compressor engine emissions calculation procedure, the adjusted emissions provided by the production companies were used. These emissions are summarized in Table 13.

Table 13. Compressor engine emissions for the Ute Mountain Ute.

Reported 2005 Compressor Engine NOx Emissions (tons)[31,32]	409
2002:2005 Multiplier	1.1
Estimated 2002 Compressor Engine NOx Emissions (tons)	450

Reconciliation of Tribal and State Inventories

After obtaining the necessary activity data, emissions estimates were completed for the tribes using the same methods developed for the rest of the WRAP region. That drilling and production data for the tribes was available from the state OGCs was fortunate given the lack of alternative sources of data. However, as the inventories developed for the states had used the complete set of drilling and production data maintained by each state OGC the tribal inventories clearly included emissions that had also been assigned to the states. In other words, a certain level of double counting of emissions would result by joining the state and tribal inventories. Reconciling these two inventories was not simply a matter of subtracting the emissions assigned to tribal jurisdictions from the state inventories.

Three factors complicated the reconciliation of the state and tribal inventories. First, as was described above, some emissions estimates were not made using only the data obtained from the OGCs. Adjustments were made when additional information was available from the tribe. Because the information had not been utilized in the state inventories, only the emissions that would have resulted from the exclusive use of the state data were subtracted from the state inventories. The second complication was the different control regime on state and tribal lands. Uncontrolled emission factors were used in the tribal inventories based on the absence of control requirements for these minor sources in the three tribal jurisdictions. In some cases, the corresponding emissions had been estimated in the state inventory using a controlled factor and it was therefore necessary to extract only the controlled emissions estimate from the state inventory. Finally, in the case of the Navajo Nation and the Ute Mountain Ute, emissions assigned to the tribal inventories had previously been assigned to several counties in more than one state. In this situation it was necessary to subtract from each county inventory only the fraction of emissions corresponding to activity that had occurred in that county.

By taking these steps to reconcile the state and tribal inventories, it was possible to merge the two into a single geographically comprehensive year 2002 oil and gas inventory for the WRAP. A summary of the NOx emissions included in this inventory is presented in Table 14.

Table 14. Summary of 2002 NOx emissions in the area source oil and gas inventory.

State/Tribe	Drill Rigs	Compressor Engines	Oil Wells	Gas Wells	CBM Wells	Total
Arapahoe and Shoshone	188	754	5	221		1,169
Ute Mountain Ute	2	478	0	59		540
Navajo Nation	8	667	13	469	9	1,167
Alaska	877			9		886
Arizona						
California*						8,070
Colorado	5,734		9	15,915	1,489	23,147
Idaho						
Montana	1,044	2,027	42	4,678		7,792
Nevada	24	33	1	4		62
New Mexico	6,645	40,095	122	13,360	225	60,446
North Dakota	1,536	2,920	75	101		4,631
Oregon		73		12		85
South Dakota	36	284	3	44		367
Utah	676	2,371	19	2,123		5,190
Washington						
Wyoming	4,964	7,025	106	6,177	1,428	19,699
Total	21,735	56,728	396	43,172	3,150	133,251

*Emissions for the State of California adopted from the State's area source emissions inventory.

WRAP - PROJECTED STATE AND TRIBAL 2018 INVENTORIES

Two methods were used to estimate 2018 county level oil and gas emissions. The first and by far the dominant method was to develop growth factors to project from the 2002 oil and gas emissions. A second method was then 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 growth factors used to project county level emissions from 2002 to 2018 were derived from projections of future oil and gas production reported by several sources. The preferred source of production projections was the 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 (RFD). Table 15 provides a brief summary of the RFD scenarios used to obtain the necessary information for creating the 2002 to 2018 growth factors.

Table 15. BLM Resource Management Plans considered for use in projections.

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

As shown in Table 15, we obtained a number of RMPs covering a large portion of the WRAP production areas. In addition to the BLM studies, the Alaska Department of Natural Resources prepares 20-year production forecasts that were used in this effort[33]. For the remaining areas, regional production forecasts published by the Energy Information Administration were used[34]. For those areas where EIA forecasts were the only source of data identified, separate oil and gas growth factors were 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. Growth factors developed for those regions based on the EIA's production forecasts are shown in Table 16.

Table 16. 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

Projections to 2018 based on the BLM RMP 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. As the RMPs do not include estimates of the number of wells that will be plugged and abandoned in future years, 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.

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 5.

Calculation 5: Derivation of a gas production growth factor based on BLM RMP

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

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 in the EIA forecast; 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 summary of the eight types of growth factors created is presented in Table 17.

Table 17. Projection growth factors.

Data Source	Growth Factor	Derivation	Sources Grown
EIA	Gas production	2018 estimated gas production for the region divided by 2002 gas production for the region	• Compressor Engines • CBM Pump Engines • Gas Well - Minor NOx & VOC sources
EIA	Oil production	2018 estimated oil production for the region divided by 2002 gas production for the region	• Oil Well - Minor NOx & VOC sources
EIA	Well drilling	2018 estimated wells drilled in the lower 48 divided by 2002 wells drilled in the lower 48	• Drill Rigs
Local	Gas wells	2018 estimated gas wells in the planning area divided by 2002 gas wells in the planning area	• Gas Well - Minor NOx & VOC sources
Local	Oil wells	2018 estimated oil wells in the planning area divided by 2002 oil wells in the planning area	• Oil Well - Minor NOx & VOC sources
Local	CBM wells	2018 estimated CBM wells in the planning area divided by 2002 CBM wells in the planning area	• CBM Pump Engines
Local	Gas production	2018 estimated total gas production in the planning area divided by total 2002 gas production in the planning area	• Compressor Engines
Local	Well drilling	Number of wells drilled per year suggested by the development forecast divided by the number of wells drilled in 2002	• Drill Rigs

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.

Independent 2018 emissions estimates

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 6.

Calculation 6. 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

This number of 2018 oil, gas, CBM and/or drilled wells predicted by the RMP 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, CBM 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 was adopted. The emission factors that resulted for NOx are shown in Table 18. Emission factors for other pollutants were developed by the same approach.

Table 18. 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**
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 18 were combined with development forecasts as shown in Calculation 6 to produce the county level emissions. These emissions estimates were then combined with the projected 2018 emissions to produce a comprehensive 2018 area source oil and gas emission inventory.

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 identified and the actions taken to incorporate them into the 2018 projections is provided in Table 19. 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 were adopted by the 2018 inventory.

Table 19. Projection information provided by State DEQ.

State	Future Controls	Action
All	Nonroad diesel engine standards[14]	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[14]	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
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[21]	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.

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

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. Control factors were derived as the 2018 emission rates divided by the 2002 emission rates. 2018 emissions were then calculated as the product of the county control factor and the uncontrolled 2018 emissions estimate.

SPATIAL ALLOCATION

For air quality modeling ENVIRON developed a new set of spatial allocation surrogates 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 20, 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 20. 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

Latitude and longitude coordinates for oil and gas wells and drill rigs were obtained for the WRAP states, except California. These locations are plotted in Figure 1. Once the well and drilling 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.

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. Figure 2 shows an example of the surrogates that resulted from this procedure.

Figure 1. Locations of wells and drill rigs.

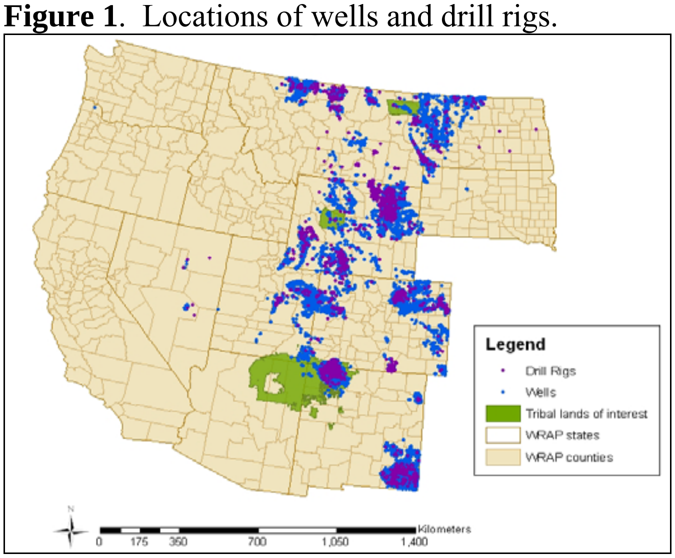
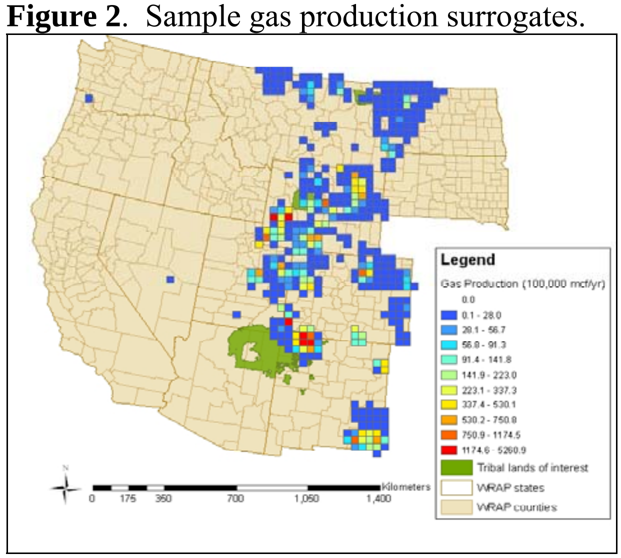


Figure 2. Sample gas production surrogates.



GAS COMPRESSOR ENGINE EMISSION CONTROLS

In 2004, NETAC commissioned a pilot project to demonstrate the effectiveness of available technology in reducing NOx emissions from compressor engines used in gas production operations. In the early stages of the project, representatives of NETAC, in consultation with gas compressor engine operators, identified small (less than 500 horsepower), rich-burn gas compressor engines as the best candidate group for retrofit. A non-selective catalytic reduction (NSCR) system was determined to have the greatest potential for reducing NOx emissions from this type of compressor engine. NSCR reduces NOx, carbon monoxide (CO) and hydrocarbon (HC) emissions simultaneously if an engine is operating at the stoichiometric air/fuel ratio. In order for the catalyst to achieve high conversion efficiencies for all three pollutants, the air/fuel ratio must be held close to the stoichiometric point using an electronic air/fuel ratio controller. The complete system, as installed on one of the test engines, is shown in Figures 3 and 4.

Figure 3. Retrofit system: power supply

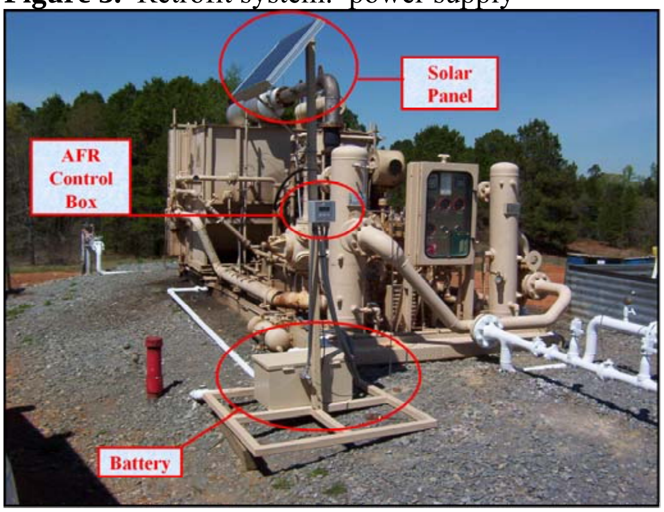
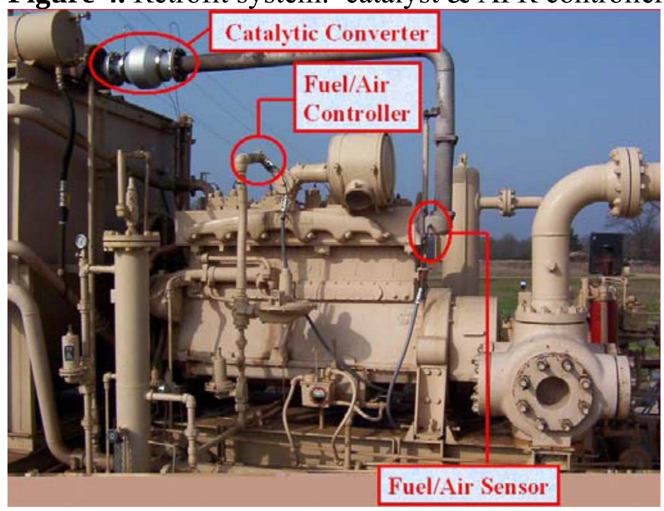


Figure 4. Retrofit system: catalyst & AFR controller



Baseline and post-retrofit emissions tests were performed on all five engines by third-party specialists qualified to use EPA-defined test methods. For two engines it was possible within the timeframe of this project to conduct additional post-retrofit tests after the engines had been operating more than 4,000 hours. This additional testing was done to establish the longevity of this control strategy. In this test, a comparison was made of the “pre-catalyst” (exhaust gases on the engine side of the catalyst) and “post-catalyst” (exhaust gases on the exit of those gases to the atmosphere) emission rates. The comparison of pre- and post-catalyst emission rates during the longevity testing shows that the catalyst is still functioning with high reduction efficiency after 6 months of continuous operation. A summary of the testing results is provided for each of the engines in Table 21.

Table 21. Summary of NOx emissions reductions.

Engine Description		Tested Emission Rates		Reduction of NOx Emissions	Longevity Testing	
Engine ID	Engine Description	Baseline (g/hp-hr)	Post-retrofit (g/hp-hr)		Pre-Catalyst (g/hp-hr)	Post-Catalyst (g/hp-hr)
70640	CAT 342 NA	11.61	0.26	98%	26.81	0.99
74236	CAT 3306 TA	13.01	0.55	96%	20.77	0.85
70024	CAT 342 TA	13.29	0.49	96%		
75558	CAT 3306 TA	12.70	0.36	97%		
72386	CAT 3306 NA	12.43	0.47	96%		

To estimate the cost per ton of NOx abatement it was necessary to derive annual NOx emissions reduction based on the measured emission rates. The calculation of annual emissions reductions required an assumption of the operational schedule of gas compressor engines. The nature of gas production and information provided by gas compressor operators suggests that gas compressor engines operate nearly year-round. The exception to this is periods when the engines are shut down for repairs or maintenance. For the purposes of this cost effectiveness calculation it was assumed that the engines will operate 8,000 of 8,760 hours per year. The loading of the compressor engines was estimated based on the average loading at the time of emissions testing. The average load before and after installation of the catalyst ranged from 41 to 66 percent for the five engines. Using these assumptions and the emission factors determined from emissions testing, annual emissions reductions were estimated for each of the engines. The average annual emissions reduction determined for the five engines was 12.3 tons NOx per year.

For the five engines, the average cost of the control equipment and engine modifications, including air/fuel ratio controllers and the solar power units to power those controllers, was $7,672. The estimated cost of the labor required to install the equipment was $1,280 per engine. The average upfront cost of the retrofit was thus $8,952 per engine. The maintenance costs of this control system are limited to those of several regularly occurring tasks. These tasks include biannual cleaning of the catalyst, quarterly replacement of the oxygen sensor and replacement of the solar power unit's battery every four years. When the upfront and maintenance costs were annualized over an assumed five-year project life at a discount rate of 3 percent, the total annual cost estimated for the retrofit was $2,250 per engine.

The average emissions reduction of the compressor engine retrofit was derived from the results of carefully planned emissions testing. The annual cost of the retrofit was estimated based on actual installation costs and anticipated maintenance costs. From these figures it was a simple matter to estimate the cost effectiveness. The average annualized cost of installation and maintenance of $2,250, divided by the average annual emission reduction, 12.3 tons NOx, yielded a cost of $183 per one-ton reduction of NOx emissions. Thus this pilot project demonstrated that the installation of catalysts on gas compressor engines is an exceptionally cost effective strategy for achieving NOx emission reductions.

CONCLUSIONS

Table 22 compares the results of the WRAP oil and gas inventory effort with the oil and gas emissions in the inventories that were previously available. Total NOx emissions estimated by this

Table 22. Change in oil and gas NOx emissions in the 2002 inventory as a result of this study.

	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
Arapahoe and Shoshone*	1,169	54	1,223	NA	NA	NA	1,223	NA
Navajo Nation*	540	6,382	6,922	NA	NA	NA	6,922	NA
Ute Mountain Ute*	1,167	-	1,167	NA	NA	NA	1,167	NA
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	**133,251**	**187,627**	**320,878**	**14,479**	**181,191**	**195,670**	**125,209**	**64%**

*Point source inventories for the tribes were compiled by the Institute for Tribal Environmental Professionals.
**Area source emissions in WRAP Oil and Gas Inventory adopted from data submitted by the California ARB.

inventory of oil and gas emissions represent a 64 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 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 increased by over 60,000 tons.

Table 23 shows the percent change in NOx emissions projected to occur from 2002 to 2018. Oil and gas area source NOx emissions estimated for 2018 show a 115 percent increase over 2002 levels. In the total oil and gas emissions, the projected increase in area source emissions is partially offset by a greater than 50 thousand ton decrease in NOx emissions predicted for point sources. The forecast 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 23. Change in oil and gas NOx emissions from 2002 to 2018.

State/Tribe	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source	Point Source	TOTAL
Tribes	127%	33%	157%	-86%	128%	-26%	**19%**
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%		-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	**200%**	**26%**	**99%**	**-57%**	**115%**	**-30%**	**30%**

The inventories produced by these projects indicate the importance of oil and gas production as a source of emission in the western region. 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 as comprehensive nor as accurate as it might be with more resources. The inventories and the methodology used represent a first step toward a better understanding of oil and gas emissions. At a minimum, these results indicate that many states and tribes will need to carefully evaluate the impact of existing and future oil and gas production as they work to meet their air quality goals. The methods described here for compiling oil and gas emissions inventories, projecting future emissions, spatially allocating emissions, and controlling emissions from gas compressor engines should provide useful tools for those future studies.

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KEY WORDS

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