ENVIRON

QUESTIONNAIRE

To: WRAP Region Oil and Gas Producers

From: Ron Friesen, ENVIRON

Date: November 17, 2006

Subject: WRAP Oil and Gas Phase 2 Emissions Inventory Project
Questions For Producers

Introduction

ENVIRON Corporation, under contract to the Western Regional Air Partnership (WRAP), has been developing estimates of 2002 and 2018 non-point-source (area source) oil and gas (O & G) operations in the WRAP region, which includes the states of Alaska, California, Oregon, Washington, Idaho, Montana, Wyoming, Colorado, Arizona, New Mexico, and North and South Dakota. Emissions estimates derived in Phase I of this work were based on available information from state Oil and Gas Commissions (OGCs), assumptions and estimates of O & G activity in 2002, and projected growth in O & G activity. The Phase I final report on 2002 WRAP regional emissions estimates and projected 2018 emissions estimates can be found at: http://wrapair.org/forums/ssjf/documents/eictts/oilgas.html

After the Phase I WRAP work, ENVIRON prepared a detailed emissions inventory of all oil and gas area source emissions in San Juan and Rio Arriba counties in New Mexico in 2002, under contract to the New Mexico Environment Department (NMED). This emissions inventory was based on a detailed survey of O & G producer activities in the two counties and relied on a high response rate from producers operating in these counties. The final report of the NMED analysis can be found at:
www.nmenv.state.nm.us/aqb/projects/San_Juan_Ozone/NM_Area_Emissions_report.pdf

Based on these two previous analyses, ENVIRON is now engaged in a Phase II updated emissions inventory estimate for the WRAP region for 2002 and updated emissions projections for 2018. In addition, ENVIRON has been asked by WRAP to identify and quantify potential control strategies to reduce these emissions and the potential emissions reductions. The Phase II work will rely on detailed producer information for all basins in which major O & G operations are occurring. Emissions estimates will be made on a well-count basis where possible, and averaged by basin in the WRAP region. A high response rate from producers to this request for information will ensure that this new inventory will be both detailed and accurate.

The purpose of this questionnaire is to assist in the preparation of these updated 2002 and 2018 oil and gas emissions inventories. In this project, we will also be assessing the emission sources that have significant potential for reducing emissions through various control methods and technologies. The potential emissions reductions from the most promising control technologies will be evaluated for each western state and an estimate of the potential reductions in 2018 will be provided.

This document contains a detailed list of questions to producers – by emissions category – that will aid in estimating 2002 and 2018 emissions inventories. This document makes reference to the workplan developed as part of the Phase II work. The workplan document can be found as Attachment I to this questionnaire. The work plan document summarizes the background for developing the updated WRAP emissions inventory and details the methodology and approach that will be taken for each major category of pollutant that we will address. This updated inventory represents a Phase II emissions inventory and seeks to update and make improvements on the Phase I emissions inventory that was conducted previously. The Phase II inventory will rely on more detailed information from producers' on their activities in the WRAP region on a basin-wide average basis as well as information provided by the states.

Overview

The work plan addresses six categories of emissions: drilling rigs; compressor engines; CBM engines; VOC emissions from completion activities, venting and flashing; heaters; and fugitive dust. Except where noted, emissions will be estimated on a count basis, rather than a production basis. This reflects the expected availability of detailed information from producers on their activities in the WRAP region. Count-based data will be averaged within each major basin of significant O & G activity in the WRAP region.

This questionnaire is organized into two sections:

1. Section 1 contains the detailed questions for producers by emissions category
2. Section 2 contains a brief checklist for producers to indicate whether or not the information in Section 1 is available. Section 2 can also be used as a quick reference guide for the information we are requesting.

Where possible, detailed information is requested and it is preferable that this information be provided in electronic form. The information requested for drill rigs and compressor engines, as well as the general questions and questions on projections, are the most important. In order to meet our schedule for completing the WRAP emissions estimates, the deadlines for receiving information are:

1. General questions and questions on drilling rig engines - December 7, 2006
2. Questions on compressor engines and 2018 emissions projections - December 22, 2006
3. All other information - January 10, 2006

We would like to encourage producers to provide information as soon as possible so that we will have sufficient time to conduct a thorough analysis incorporating this information. We are requesting a brief response by November 28, 2006 with whether or not you will be able to provide information on the specific questions included in this questionnaire. Please use the checklist in Section 2 to indicate the availability of information on your operations. Prompt notice of how much data we can or cannot expect in advance of the actual deadline for data transfer will help ensure the best possible analysis is conducted.

ENVIRON will hold confidential all information provided by producers; we will not share specific producer information in response to the operations. We will use the information provided to aggregate and report emissions by field, formation or basin.

All information should be provided in electronic format if possible and preferably in spreadsheet format. All data should be returned to:

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If you have any questions regarding this questionnaire, or any of the questions contained here, please feel free to contact Mr. Bar-Ilan at the phone number or email address above.

SECTION 1

GENERAL QUESTIONS/COMMENTS

Please provide answers to general questions to ENVIRON by December 7, 2006.

1. Please provide an overview of your Oil and Gas operations in the WRAP region; identify the principal areas of operation and specifically in which basins you have production operations.
2. In responding to the questions below, please indicate the following for all information that you provide to us:
   - Field, formation or basin to which your information refers
   - Whether the well, field, formation or basin has conventional or CBM production
   - Whether the well, field, formation or basin is electrified
   - Whether the well, field, formation or basin has significant sour gas (H_2S) production
3. Please respond to all questions with information from calendar year 2002.

I. DRILLING RIG EMISSIONS

Please provide answers to questions on Drilling Rig Emissions by December 7, 2006.

1. What are the actual average drilling times (beginning and completion dates) for your drilling operations by formation and by basin in which the formation is located? Please provide either detailed information on drilling times by well, or an average by formation or basin.
2. What are the average drilling depths for your drilling operations by formation and by basin in which the formation is located? Please provide either detailed information on drilling depths by well, or an average by formation or basin.
3. What is the actual load on the drilling rig engine for each well? If this is unavailable, please provide an estimate of the average load of drilling rig engines operating within a formation, or within a basin. Please identify if this load is significantly different if the well is a new well or a workover.
4. What is the average horsepower of drilling rig engines used in your operations in each formation within a basin, or as a basin-wide average? Please identify if the average horsepower of drilling rig engines is significantly different if the well is a new well or a workover.
5. What is the most commonly used make and model (or up to 3 most commonly used makes and models) of drilling rig engines, grouped by horsepower, for each formation or basin in which you drill?
6. What are the manufacturers' rated emissions factors (EFs) for the drilling rig engines identified in Question 5? This should include NOx, CO, VOC, SOx and PM emissions.

7. What type of diesel fuel is used and what is the sulfur content of that diesel fuel for each drilling rig engine by formation, or by basin, or by county, or by state (as appropriate)?
8. Please provide, if possible, information on the total fuel consumption, or fuel consumption rate of drilling rig engines that you operate.
9. What percentage of drilling rig engines in each basin in which you operate use air-assist packages?
10. For those drilling rig engines with air-assist packages identified in Question 9, what is the most commonly used make and model of air compressor used in the air-assist package? What is the average load of that compressor, and what are the manufacturers' rated EFs for that compressor?

II. COMPRESSOR ENGINE EMISSIONS

Please provide answers to questions on Compressor Engine Emissions by December 22, 2006.

1. How many wells do you operate within each basin in which you operate? Please indicate number of wells and in which basin these wells are located.
2. What fraction of the number of wells in each basin in which you operate use wellhead compressors, what fraction use lateral compressors, and what fraction use centralized compressors? If this information is not available as a fraction of the number of wells, is this information available as a fraction of the total horsepower of compression in each basin in which you operate? If so, please provide the information as a fraction of total horsepower of compression in each basin.
3. What is the average load on a wellhead and/or lateral compressor engine as a basin-wide average for each basin in which you operate?
4. What are the 3 most commonly used makes and models of wellhead and/or lateral compressors in each basin in which you operate?
5. What are the manufacturers' rated emissions factors of NOx, CO, and VOC for each of the makes and models of compressor engines identified in Question 4?

III. VOC EMISSIONS

Please provide answers to questions on VOC Emissions by January 10, 2007.

1. Venting of wells occurs frequently to unload fluids that may after time reduce the amount of gas produced. How frequently do you vent wells, and what are the venting flow rates and the amount of time the wells were vented by formation or basin?
2. Have you taken any measures to reduce venting activity between 2002 and 2005? If so, what is the current frequency of venting at wells averaged by formation or basin?
3. For NMED, emissions from fugitives were estimated by defining a typical well setup for oil, conventional gas and CBM gas wells. The diagrams for these typical wells are shown in Attachment II of this document. Do these typical well setups adequately represent your operations?

4. If not, please provide as much detailed information as possible about your typical well setup, including number and type of each item of equipment typically used.
5. Do you use glycol dehydrators in the field for each basin in which you operate, or are they used only at large central gas plants? If you use glycol dehydrators in the field, please provide information on the number of these units in each basin in which you operate.
6. What are the emissions rates of your glycol dehydration units?

IV. CBM ENGINE EMISSIONS

Please provide answers to questions on CBM Engine Emissions by January 10, 2007.

1. What fraction of wells in each basin you operate are CBM wells and what fraction are conventional wells?
2. For the basins in which you operate that have significant CBM activity, which fuel is used to power CBM engines?
3. What is the typical activity of the CBM engine (hours per year of operation)? Is the engine running continuously on an annual basis, or for how much time as a basin-wide average?
4. What is the water production rate from CBM wells that you operate as a basin-wide average?
5. What is the horsepower of CBM engines as a basin-wide average?
6. What is the average load of a CBM engine as a basin-wide average? If the CBM engine is fully loaded for a fraction of its total activity time, and lightly loaded as water production decreases, what are these two loads and what fraction of the total activity time is the CBM engine running in each of these modes?
7. What are the manufacturers' rated or tested EFs for a typical or most commonly used CBM engine?
8. Are there any emissions control technology installed on a CBM engine and if so what is the effectiveness of these controls for each pollutant (NOx, CO, VOC, SOx, PM)?
9. What is the fuel consumption rate of CBM engines as a basin-wide average?

V. HEATER EMISSIONS

Please provide answers to questions on Heater Emissions by January 10, 2007.

1. How many heaters are used at each well site as a basin-wide average for each basin in which you operate? What fraction of all wells within a basin use heaters (for each basin in which you operate)?
2. What is the fuel consumption rate of heaters in the basins in which you operate as a basin-wide average?
3. What is the heat content of the gas used in heaters in each basin in which you operate as a basin-wide average?
4. What is the annual usage of heaters in each basin in which you operate, as number of hours per month for each month? If heaters are operated for some wells in some basins only during winter months, please indicate this.

5. What are the manufacturers' rated EFs for a typical make and model of heater that you operate?
6. What is the sulfur content of the fuel with which the heater operates for each basin in which you operate as a basin-wide average?

VI. FUGITIVE DUST EMISSIONS

Please provide answers to questions on Fugitive Dust Emissions by January 10, 2007.

ENVIRON may conduct an analysis to estimate fugitive dust emissions as part of the Phase II emissions inventory described above. Fugitive dust emissions are defined as re-entrained dust from unpaved roads leading to oil and gas well sites that are serviced by motor vehicles, as part of your O & G operations. Please answer the following questions about fugitive dust following the definition above:

1. Have you ever estimated or reported fugitive road dust emissions from your O & G operations in any basin or state in which you operate? If so, please provide this information.
2. Can you estimate the mileage of unpaved roads leading to well sites as part of your O & G operations in each basin and state? If so, please provide this information.
3. Can you estimate the total vehicle miles traveled (VMT) on unpaved roads leading to well sites of all vehicles that are part of your O & G operations in each basin and state? If so, please provide this information.
4. Can you estimate the average weekly or monthly number of trips on unpaved roads leading to each well site for your O & G operations, and the average miles per trip?
5. What are the typical types of vehicles that travel on unpaved roads to each of your well sites (i.e. van, pickup, truck, etc)?

VII. 2018 EMISSIONS PROJECTIONS

Please provide answers to questions on 2018 Emissions Projections by December 22, 2006.

1. For each basin in which you operate, what is the fraction of wells that have wellhead, lateral, and centralized compression for calendar years 2002 and 2005. Can you estimate these same fractions for year 2018 and any or all future years between 2005 and 2018? If this information is not available as a fraction of number of wells, is this information available as a fraction of the total horsepower in each basin in which you operate? If so, please provide this information.
2. What was the estimated average production per well as a basin-wide average in 2002? What was this production per well in 2005? What is the estimated future production per well in calendar year 2018? Please provide information for any future calendar year up to 2018 for which you have an estimate.

SECTION 2

Below is a brief checklist of the information requested in the Section 1 questions. We would like to know whether or not information on each emissions category is available before you begin to answer the questions and provide quantitative information. Please respond to the checklist below and check "Yes" or "No" to whether detailed information is available for each question in each emissions category. If some information is available but not all, please check "Yes". **Please return this completed checklist to ENVIRON by Tuesday, November 28th, 2006.**

Please note that item I – Drilling Rig Emissions, item II – Compressor Engine Emissions, and item VII – 2018 Emissions Projections are the highest priority emissions categories for purposes of this questionnaire. Please reply with information on these emissions categories as soon as possible. All other information may arrive afterwards, but no later than the January 10, 2007 deadline. The dates for specific categories are listed below.

I. Drilling Rig Emissions (due date: December 7, 2006)

	Yes	No
Drilling times		
Drilling depths		
Engine load		
Engine horsepower		
Engine makes/models		
Emissions factors		
Fuel type		
Fuel consumption rate		
Air-assist usage		
Air-assist compressors and compressor emissions factors		

II. Compressor Engine Emissions (due date: December 22, 2006)

	Yes	No
Number of wells by basin		
Fraction of wells with wellhead/lateral/centralized engines by basin		
Fraction of total compression HP that is wellhead/lateral/centralized by basin		
Average load on compressors by basin		
Average makes/models of compressors by basin		
Emissions factors		

III. VOC Emissions (January 10, 2006)

	Yes	No
Frequency of venting at wells		
Venting flow rates		
Venting times		
Recent changes in venting frequency		
Typical well setups		
Glycol dehydrator usage		
Glycol dehydrator emissions rates		

IV. CBM Engine Emissions (due date: January 10, 2006)

	Yes	No
Fraction of CBM wells/conventional wells in each basin		
CBM engine fuel		
CBM engine activity		
Water production rates		
Average horsepower of CBM engines		
Average load of CBM engines		
Emissions factors		
Emissions control technology		
Fuel consumption rate		

V. Heaters (due date: January 10, 2006)

	Yes	No
Number of heaters per well		
Fraction of wells with heaters		
Average fuel consumption rate		
Average heat content of heater fuel		
Annual or monthly activity of heaters		
Emissions factors		
Sulfur content of heater fuel		

VI. Fugitive Dust Emissions (due date: January 10, 2006)

	Yes	No
Estimates or reports on fugitive dust from your operations		
Mileage of unpaved roads leading to well sites		
VMT of vehicles traveling on unpaved roads to well sites		
Average weekly or monthly number of trips to well sites		
Types of vehicles traveling on unpaved roads to well sites		

VII. 2018 Emissions Projections (due date: December 22, 2006)

	Yes	No
Fraction of wells by basin with wellhead/lateral/central compression in 2002		
Fraction of wells by basin with wellhead/lateral/central compression in 2005		
Estimate of fraction of wells with wellhead/lateral/central compression for any calendar year between 2005 and 2018		
Production per well by basin for 2002		
Production per well by basin for 2005		
Estimate of production per well by basin for any calendar year between 2005 and 2018		

ATTACHMENT I

Work Plan for WRAP Phase II Oil & Gas Area Source Emissions

Work Plan

WRAP AREA SOURCE EMISSIONS INVENTORY, PROJECTIONS AND CONTROL STRATEGY EVALUATION

Prepared for

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November 9, 2006

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1. INTRODUCTION

This work plan describes the procedures proposed to estimate an improved inventory of emissions from oil and gas (O & G) exploration and production activities in the Western Regional Air Partnership (WRAP) states, a projection of emissions in the WRAP region for calendar year 2018, and an analysis of current and future control strategies and their impacts on future emissions. This work plan represents a second phase of emissions inventorying and forecasting work being conducted by ENVIRON in the WRAP region.

The proposed work would build upon ENVIRON's previous work for the WRAP in which we developed and implemented uniform procedures for estimating emissions from oil and gas production operations across the western states (final report "Oil and Gas Emissions Inventories for the Western States," dated December 27, 2005). The emphasis of that study was placed on estimating emissions of pollutants with the potential to impair visibility near Class I areas in the west, in particular oxides of nitrogen (NOx). Some emissions estimates were also provided for SO2 from drill rigs and VOC from some wellhead processes. Emissions were estimated for the year 2002 and projected to 2018.

The oil and gas production industry includes a number of processes and equipment types that stretch from the wellhead to fuel distribution networks. While the largest oil and gas production facilities such as major compressor stations and gas plants had been inventoried in the past (as part of stationary source emission inventories), the equipment types that were the focus of this study are geographically distributed and are considered area sources. Prior to ENVIRON's earlier work, there were essentially no regional emissions estimates for oil & gas area sources, and this study was the first such emission inventory. The present proposal uses this prior ENVIRON work as the basis for further work to improve the estimates.

After the original WRAP oil & gas emissions work was completed, ENVIRON developed improvements to oil and gas area source emissions in two counties in northwest New Mexico (San Juan and Rio Arriba) under contract to the New Mexico Environment Department (NMED), ENVIRON. In this work the analysis relied on extensive and detailed information obtained from surveys of producers in the two New Mexico counties, and emissions were inventoried on the basis of the producer information.

The current effort aims to improve upon the original WRAP area-wide inventory (Phase I), by updating the methodology used to generate the emissions inventory, updating information on control strategies, and updating the 2018 emissions projections including the impact of the updated control strategies on these emissions. The work plan addresses these three tasks and two additional, optional tasks:

1. Improvements to the 2002 Emissions Inventory
2. Control Strategies for O & G operations
3. 2018 Emissions Forecasts and Potential Control Strategies by State
4. (Optional) Updating Baseline Emissions from 2002 to 2005
5. (Optional) Improvements to Point Source SO_2 Emissions in 2018

Tasks 1, 2, and 3 are the primary focus of this work plan. Task 1 will include, at a minimum, an updated methodology to improve emissions estimates from drilling rig engines using the methodology developed in the NMED analysis; an updated methodology for estimating wellhead compressor engine emissions based on regional variations in O & G operations as detailed by producers' information; and updating CBM emissions using best available producer information. Additional 2002 inventory updates, described in the work plan, will be done if resources are available. Task 2 will involve examining current and future control technologies and applying them to projected emissions on a state-by-state basis. Task 3 will include improvements to the projection methodology to account for changes in gas production in the WRAP region. The technical details of these tasks and our proposed methodologies are described in detail in the sections below.

We have included in this work plan two additional optional tasks at the request of WRAP. The first is to estimate emissions in 2005 using 2005 state OGC data on production and well counts. The 2005 emissions would then be used as the baseline inventory for the 2018 projections.

The second optional task is to revise the emissions of SO_2 from large point sources due to O & G operations in the WRAP region in 2018. These point sources are primarily natural gas processing plants located in Wyoming and New Mexico and to a limited extent in Colorado and Utah. These plants' SO_2 emissions projections have been recently revised for the SSJF by Pechan, but the growth factors used in projecting these emissions have not included recent advances in SO_2 removal technology that producers have been increasingly utilizing to reduce SO_2 emissions from these sources. The purpose of this optional task is to revise the control assumptions, and more importantly to develop the projection factors based on the 2018 production projections that will be developed in Task 3.

2. TASK 1: 2002 EMISSIONS INVENTORY IMPROVEMENTS

This task focuses on improving estimates of the emissions inventory of NOx, SOx and PM from O & G operations. These criteria pollutants can have serious potential health consequences, are smog-forming precursors, and can negatively impair visibility. VOC emissions will be estimated on an as-needed basis but will not be a major focus of the proposed work both due to feasibility constraints and due to the relatively low emissions of VOCs from O & G operations as compared to the other pollutants of interest. However VOC emissions from selected O & G operations in certain areas may be significant and will be addressed in order of priority.

The most significant emissions of NOx, in the WRAP regions are from drill rigs and from natural gas-fired compressor engines. The most important sources of SOx and PM emissions are from drilling rig engines, and from minor H_2S emissions in some O & G operations in southwest New Mexico. Some effort will be made to distinguish between emissions from conventional gas wells and coal bed methane (CBM) gas wells as these are expected to have some differences.

Prior work in the WRAP region was limited by available information and accordingly, certain assumptions about O & G production can be improved upon. The Phase I work made estimates of drilling time and activity on the basis of state Oil and Gas Commissions (OGCs) which does not provide enough detail for an accurate calculation of actual drilling times. Drilling rig engine loads were assumed to be at the maximum capacity for that engine, and a similar assumption was made for compressors. Actual loads vary significantly with the type of O & G operation being considered and vary widely particularly for compressor engines. An inventory project for the New Mexico Environment Department (NMED) focused on improving these estimates and assumptions, but studied only O & G operations in San Juan and Rio Arriba counties in northwest New Mexico. Thus this work was limited to the types of operations in this geographic region. Phase II work will focus on expanding the types of revised estimates made in the NMED work to other WRAP producing regions, as well as incorporating more recent information from producers in the WRAP region on their specific utilization of drilling rigs and gas compressors in their O & G operations. The revised estimates will make use of information about the geography of the O & G operations and the producers' specific operations. In addition to producers, we will contact each of the environmental departments in the respective states to obtain information that either was already provided by the producers or was developed by the respective agencies. Work will focus on drilling rigs, gas compressor engines, CBM operations, and to a limited extent VOC emissions from flaring/venting. A listing of the major tasks in the emissions inventory, ranked in order of priority, are shown below in Table 2-1. Tasks 1 and 2 will be the focus of the work for this phase of the project, Tasks 3 and 4 will be accomplished providing that there is sufficient time and resources.

Table 2-1. Recommended ranking and description of Phase II emission inventory improvements.

Rank	Emissions Source	Improvements to Phase I Emissions Estimates
1	Drilling Rigs	• Update and improve estimate of drilling times by using actual drilling stop times • Improve estimates of engine type, make/model, and inventory based on information from producers • Use producer information to better estimate engine load factors. • Incorporate projected emissions from air-assist packages. • Incorporate PM and SOx emissions factors to estimate PM and SOx emissions from drilling rig engines.
2	Compressor Engines	• Use information from producers on actual wellhead compression activity to better estimate mix of wellhead, lateral and centralized compression on a basin level. • Use average field pressure over a basin to better estimate actual compressor engine load. • Incorporate PM emissions factors to estimate PM emissions from compressor engines.
3	VOC Fugitives/Venting	• Utilize analysis in NMED inventory to improve estimates of venting and fugitive emissions. • Determine usage of glycol dehydrators on a field basis and estimate emissions from these units based on producer information.
4	Fugitive Dust	• Investigate availability of information on vehicle activity and road construction in fields and basins with high levels of production. • Determine and recommend an approach to estimating fugitive dust emissions from well sites.

Field/Basin Information

This phase of the WRAP O & G inventorying will improve upon the previous Phase I work by making use of specific information at the basin level to determine equipment types, equipment number, operating conditions, and emissions information where available. In order to facilitate collection of this information, a group of major operators will be contacted to provide information on their O & G operations in the WRAP region. Each operator will be asked to answer a series of questions regarding their operations and to provide information on their operations where such information exists. In preparing this workplan, we have had lengthy conversations with several operators to obtain preliminary information regarding improvements that can be made to emissions inventory. The major operators contacted to date are listed in Table 2-2. Exxon and Shell are also major operators in the WRAP region and will be contacted as part of the survey.

Table 2-2. Major producers in the WRAP region contacted to date.

Operator	Regions and Operation Type	Contacted? (Y/N)
BP	Southeast NM (oil, gas) Northwest NM (gas, CBM) Four Corners Area (CBM) Southwest WY (gas, CBM)	Y
Chevron	Southeast NM (oil, some gas) Four Corners Area (CBM) Northwest CO (oil) Southwest WY (gas) Central WY Alaska (oil)	Y
Duke Energy	Southeast NM (gas)	Y
Conoco/Phillips	Northwest NM (gas) Southeast NM (oil) Southwest CO (gas)	Y

Information obtained from the producers will also be used to better identify types of fields where major O & G operations are occurring and if specific operator information is available. Field information will include field pressure, average drilling times for the field, average drilling depths for the field, and whether conventional or CBM wells are primarily drilled.

Based upon the information already supplied by producers, we intend to focus our efforts on those areas where significant production is occurring. These include the Four Corners region, Southeast New Mexico, Utah, Colorado, Southwest Wyoming, North Central Wyoming, and Northeast Wyoming. Montana, Idaho, Washington, Oregon, Nevada and Arizona will not be a focus of this phase of the emissions inventory analysis because O & G operations occurring in these areas are less significant. California will not be included because O & G operations have been inventoried and regulated through the California Air Resources Board (CARB). O & G operations in Alaska will be largely limited to drilling rig emissions, because most of the gas compression in Alaska is assumed to be handled through large centralized stations that are considered point sources and have been included in point source inventories. However, based on producer information it will be determined whether any small area sources emitting below the point-source inventory cutoff must be included in the Alaska emissions inventory.

The proposed methodology will involve collecting producer information on specific basins where the producer has significant operations. Each producer can provide information only on their detailed operations, and these data will be used to estimate overall average characterization of O & G operations and emissions in the basin. Where multiple producers are operating extensively in a single basin, each producer’s detailed information will be used to create a weighted average of activity based on each producer’s well count in the basin as a fraction of the total well count. The analysis is to be conducted on a basin level because information from producers indicates that O & G operations tend to be similar within a basin, but vary widely from one basin to the next. Thus a detailed analysis of an individual producer’s operations in a basin can be carried out and averaged basin-wide by well count in that basin. However, where significant differences occur within a basin, we plan to identify those differences by field. This approach has the additional advantage that it can account for differences in state point source inventories and emissions control regulations.

For this effort we will use the database of well-specific information from state OGC's that was developed in the Phase I analysis to identify basin boundaries and the well counts within each basin, and within each county. This approach then relies on specific producer information, which was not available at the time of the Phase I inventory analysis. Thus, this information can be used to selectively improve the emissions estimates of individual basins. We intend to focus our efforts on those basins that have the greatest potential for improvement of the inventory. These include, but are not limited to, the Permian and San Juan Basins in New Mexico (the San Juan Basin has already been well-characterized in ENVIRON's analysis for NMED); the Powder River, Wind River and Southwest Wyoming Basins in Wyoming; a portion of the Uinta-Piceance Basin in Utah. Operations in Colorado were not included in the O & G area sources inventory in the Phase I analysis because Colorado accounts for all sources emitting 2 tpy or greater in the state as point sources. Similarly to Alaska, we will determine from producer information whether any small area sources below the 2 tpy limit of the point-source inventory must be included in our updated area source emissions inventory for Colorado.

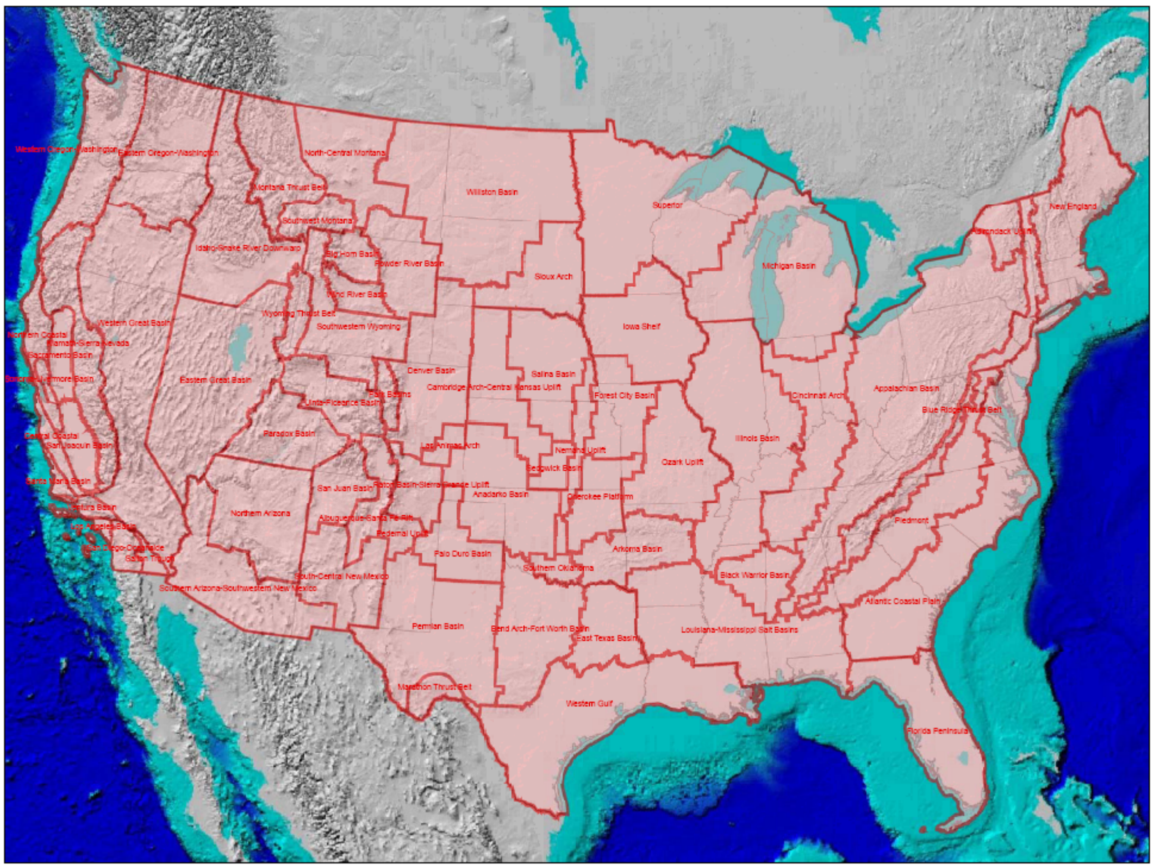


Figure 2-1. Basins in the lower 48 states in which oil and gas operations are occurring.

It should be noted that where specific information on operations in a basin are not available, this analysis will assume that those emissions are as estimated in the Phase I analysis. Thus we can selectively improve the inventory based on the availability of producer information on their operations in specific basins.

The detailed description of the tasks involved in updating the 2002 emissions inventory is described below. We have ranked the tasks in order of priority beginning with drilling rig and compressor emissions. At a minimum, these two subtasks (a) and (b) will be conducted; additional subtasks (c) – (f) will be conducted if resources are available.

a) Drilling Rigs

Emissions from drilling rigs were estimated in the Phase I work based on the drilling time, drilling depth, the manufacturers rated emissions factor for NOx, SOx and VOCs, and an assumed engine load of 100%. The methodology used for estimating emissions in a particular formation was based on the average duration of well preparation activities and average well depth within the formation. Where no information was available for depth and duration, an average depth and duration of all wells in the particular formation was used. Another important assumption was the total duration of preparation activities. The actual information on the total duration was not available because the date that drilling ceased was not available in the OGC databases; only the completion dates were available. The completion date is not the date that the drilling ceased, and the Phase I analysis assumed that drilling times would be a fraction of the well completion times based on detailed information on drilling times in the Jonah-Pinedale region provided by the Wyoming DEQ. The analysis assumed that the capacity of the equipment used to drill a well is dependent upon the depth of the well. This information was combined with manufacturers rated emissions factors, obtained from the manufacturers of specific drilling rig engines.

The NMED work improved these estimates for northwest New Mexico by obtaining drilling stop times from operators in this region (rather than well completion times), by obtaining actual horsepower and emissions factors characteristics of each engine inventoried, and by derating the maximum power of the engine to account for altitude. Also, the NMED work made use of emissions testing conducted on three representative drilling rig engines manufactured by Detroit Diesel to derive representative emissions factors for drilling rigs.

For the proposed work, we will leverage the additional information provided to us directly by producers. This information will allow for an improved estimate of actual drilling stop times and drilling horsepower needs. We will endeavor to estimate drilling times for each formation; however due to resource limitations, an average will be used for all formations in a basin where detailed information on all formations is not available. This will correct for any potential errors in drilling time estimates made in the Phase I where the drilling times were extrapolated as a function of total well preparation time from only the Jonah-Pinedale region. The producers contacted as part of our current analysis have indicated that the Jonah-Pinedale area may not be representative of drilling needs and activities at other locations. Based on information obtained from producers and the NMED analysis, actual drill times and therefore drilling emissions may be overestimated because drilling rigs are removed from operation once a desired well depth has been reached. Any remaining operations at the well are handled by well completion equipment. Emissions estimates have already been made in the Phase I work for completion equipment. Those estimates will be reviewed and compared to detailed producer information to determine if improvements can be made. All information gathered for specific formations can then be averaged over the basin in which the formations are located. For the San Juan Basin in New Mexico, we will make use of the detailed drilling information collected as part of the NMED analysis.

Previous estimates of drilling rig power and load can be improved by using producer information for specific applications. Based on information obtained to date from BP, Chevron and Conoco Phillips, the drilling horsepower requirements are based upon the anticipated drilling depth and drilling time, rather than by the formation type. This information will be used to estimate the required total drilling horsepower, taking into account as well that drilling operations typically use overpowered engines for drilling operations. The load factors used for drilling rig engines in previous estimates will be improved upon based on specific information from producers. The preliminary information indicates that the 100% load assumed in the Phase I work were incorrect and that in fact drilling rig engines are often operated at loads of approximately 50% due to the fact that the engine is overpowered for the drilling application. Where information is available from producers about drilling engine load factors those will be used. Load factors can then be averaged over all formations in a basin.

By grouping drilling rig engines by horsepower used for a specific basin, the emissions factor estimate can be improved by using specific emissions factors for the 2002 drilling requirements. This will be done similar to the NMED analysis by obtaining manufacturers rated emissions factors for a wide range of makes/models of drilling rig engines. Where this information is unavailable, the EPA's NONROAD2005 model can be used to derive emissions factors for representative horsepower categories of drilling rig engines. This will include PM emissions factors that had not been included in the Phase I work and some effort will be made to determine both $PM_{2.5}$ and PM_{10} emissions factors separately where this information is available.

Based on information obtained from producers, SO_2 emissions from drilling rig engines are expected to be a major source of SOx emissions in O & G operations. The SOx emissions will be a function of the sulfur content of the fuel used by the drilling rig engines. Total SOx emissions will be estimated by using fuel consumption data for drilling rig engines where such information is available directly from producers, or extrapolated from this information to other drilling operations. In some states regulations on the use of on-road diesel fuel will be taken into account in determining SOx emissions from formations in those states.

This analysis will also estimate emissions from air-assisted drilling. Air-assisted drilling makes use of compressed air as the circulating fluid to improve penetration rate for primarily shallow CBM or oil wells. Air-assist is not used in conventional gas wells due to the risk of accidental explosion. Producer information on the percentage usage of air-assist packages will be used to determine the types of wells and fields where such equipment is used and the average reduction in drilling times associated with usage of air-assist packages. It should be noted that the reduction in drilling times associated with the use of air-assist packages will already be accounted for by the shorter drilling times in the formations where this equipment is used. However, producer information indicates that air-assist packages use compressors to provide compressed air, therefore the analysis will include potential NOx, PM and SOx emissions from these compressors. The manufacturers rated emissions factors, or the NONROAD2005 model will be used to estimate the emissions from air-assist compressors.

The scale-up of producer information on individual formations to a basin-wide drilling rig emissions inventory will be conducted on the basis of well counts in that basin. This is similar to the approach used in the Phase I work, however the well counts will be summed in a basin, rather than a county, and the fraction of wells in a specific basin in a specific county will be summed to produce county-wide drilling rig emissions.

b) Compressor Engines

Compressor engines represent another large source of NOx and PM emissions. The Phase I analysis used detailed information about compressors obtained from a study conducted by the New Mexico Oil and Gas Association (NMOGA) on compressor engine emissions from O & G operations in Rio Arriba, San Juan, and Sandoval counties in Northwest New Mexico. This analysis allowed for the derivation of a single emissions factor based on gas production, and this was scaled up to the rest of the WRAP region on the basis of production. This assumption was necessary because detailed producer information was not available. For the NMED analysis, such detailed information was available, and a more accurate compressor emissions inventory was possible, but only for the San Juan and Rio Arriba counties in New Mexico where the work was focused.

We will expand on the NMED work to determine the types of gas compression occurring at various basins based on producer information. The methodology we propose to use will be to attempt to determine a basin-wide average percentage of wells that use wellhead or lateral compression. Because this analysis will be specific to a basin, it will account for the expected wide variations between basins in terms of required compression. For basins with high field pressures (or many virgin fields) it is expected that most compression can occur at larger centralized stations, and for basins with many mature fields there may be a significant fraction of the wells that use wellhead compression. The wellhead compressors are needed in these low-pressure fields to boost pressure to transmission line pressures. This information will come from detailed inventories collected by producers, some of whom have already indicated a willingness to provide this information in basins where they operate. In fields or basins where such information is not available, a basin-wide average will be derived to determine percentage of wellhead compression. It should be noted that this analysis explicitly assumes that the centralized stations will have already been included in the point source inventories of various states. The criterion for categorizing compressor emissions sources as point sources varies from state to state, from as high as 100 tpy in Utah to as low as 2 tpy in Colorado. These point source inventories' criteria will be rechecked to determine that no additional area sources have been overlooked in each basin.

For each basin or field in which producer-specific information is available, that information will also allow for a calculation of average load factor and wellhead and lateral compressor horsepower. The load factor offers a chance to make a significant improvement to the emissions inventory from compressors, since the load is expected to vary widely from basin to basin (or field to field) due to the maturity of the field or other geological factors. These can be accounted for in our proposed methodology, even if only on a basin-wide average basis. Similarly to the Phase I analysis, we will assume that compressor activity is 24 hours per day, 365 days per year. Emissions factors for compressors will be obtained basin-wide from producer information. If possible, a most commonly used make and model of compressor engine will be identified for a particular basin and its manufacturer's rated emissions factors will be used as representative emissions factors for that basin. If a producer has specific emissions test data for that compressor engine, that information will be used preferentially. Where it is not possible to identify a most commonly used make and model, producer information on makes and models will be used to determine an average emissions factor for compressor engines in that basin. If no information on emissions factors is available from producers or from manufacturer's ratings the EPA's NONROAD2005 model will be used to estimate emissions factors from different compressor engine types. In all cases, we will determine the emissions factors of the compressor engines for NOx and PM emissions. Although producer information indicates that PM emissions are expected to be negligibly small from compressor engines, this information will be gathered and the assumption of negligible PM emissions will be verified.

This information on emission factors, load, horsepower and percentage of wellhead or lateral compression occurring in a basin will be combined with well count by basin, by county to scale up to county level compressor engine emissions following the formulas:

$$E_{county,wellhead} = \%_{wellhead} N_{basin,county} \left(Activity * Load_{wellhead} * EF_{wellhead} * HP_{wellhead} \right)$$

$$E_{county,lateral} = \%_{lateral} N_{basin,county} \left(Activity * Load_{lateral} * EF_{lateral} * HP_{lateral} \right)$$

where E is the total emissions of either wellhead or lateral compression in the county, $N_{basin,county}$ is the number of compressors in the basin by county, *Activity* is the yearly activity of the compressors, *Load* is the load factor of the compressors as a basin-wide average, *EF(Load)* is the emissions factor of the identified average compressor in the basin, and HP is the horsepower of the identified average compressor in the basin. Again, this geographic information on well count by basin by county has already been compiled from the state OGCs in the Phase I work. As mentioned above, in cases where multiple producers have extensive operations in a single basin, these operations will be given a weighting by well count in the final average basin and hence county emissions estimates. Where information for a specific basin is not available, the analysis will use the emissions inventory estimates for that basin from the Phase I work, based on production and an assumed emissions factor.

Some compressors are expected to be electrified where wells are located close enough to power lines for electrification to be viable. However, it is expected based on the Phase I analysis that only a small fraction of compressors will be electrified.

SOx emissions from compressors will also be a function of the sulfur content of the fuel used in the compressors. According to information provided by the two major producers contacted – BP and Chevron – most of these compressors run on natural gas that has no sulfur content (also termed “sweet gas”). Where high sulfur content natural gas is being produced, the sulfur is removed from the gas prior to being used in the compressor, due to potential corrosion and durability issues with sulfur in the compressor engine. Based on this information, it is not expected that SOx emissions from compressors represent a significant source of sulfur emissions. H_2S emissions from venting of gas in sour gas production will be addressed separately.

c) CBM Wells

The previous inventories have not attributed much NOx emissions to CBM development compared to emissions from other categories, so potential inventory improvements will be evaluated in this area to verify if this is true for the entire WRAP region. Specific basins where significant CBM wells are located will be identified based on producer’s information and the extent to which CBM operations are occurring in those basins will be assessed and included, if appropriate, in the region-wide inventory. Those basins with significant CBM activity include San Juan, Powder River, and the Raton Basin-Sierra Grande Uplift.

CBM well activity is expected to be different in terms of drilling rig emissions and compressor emissions compared to conventional wells. However, in light of the new proposed methodology of averaging these emissions over a basin, we believe that this difference will be accounted for by examining drilling rig engine requirements, drilling times, completion activities, compressor engine types, emissions factors, loads, etc. for a basin in which significant CBM activity is occurring. The only major emissions source that must additionally be accounted for are CBM pump engines used to remove water from the well. The NMED analysis used water flow rates as a metric to estimate CBM engine emissions and we believe that this assumption is valid for the WRAP region inventory. Discussions with BP and Chevron have indicated that other than water pumps, CBM well development is similar to other low-pressure gas wells so no additional emissions will be attributed to these wells.

d) Heaters

Heater emissions were estimated in the NMED inventory by estimating the number of heaters necessary for well operations by well type: conventional wells require heaters only for separators, and CBM wells require additional tank heaters in winter when there is a risk of the tank water freezing. Using these assumptions the annual fuel consumption (MMBtu) of heaters was estimated at a CBM and a conventional gas well. Using AP-42 emission factors for fuel combustion NOx and CO emissions for heaters at each well type were calculated. SO_2 emissions were estimated as well using the estimated basin average H_2S concentration and the conversion of 1000 Btu/scf for natural gas. These assumptions will be verified for this work and applied to additional fields based on the mix of conventional and CBM wells.

e) VOC Emissions

VOC emissions were estimated in the 2002 WRAP inventory for tanks including flashing, working and breathing losses, glycol dehydration units, pneumatic devices and completion activities (flaring and venting). The emission factors used for estimating VOC emissions were those developed by the Wyoming DEQ and the Colorado DPHE. Because these emission factors are based on production, well-specific production data were used to estimate the emissions for other areas. Adjustments were necessary to account for the lack of specific data such as the oil versus gas production where not available (e.g., Colorado), and the identification of coal bed methane versus traditional gas wells where not available (e.g., Northwest New Mexico).

We propose to look at three areas were VOC emissions estimates may be improved: venting, fugitives and glycol dehydrators. Emissions of venting and fugitives will be evaluated to determine if significant improvements can be made to the previous emissions estimates using the procedures and assumptions from work conducted for the NMED. For venting emissions, BP (the largest producer in NW NM) provided their estimates of venting flow rates. While the venting rates may differ from other producers, these estimates provide an updated method for estimating venting emissions. Comparing BP’s venting rates to similar gas productions we arrived at an estimate of the volume of gas vented per volume of gas produced for Northwest New Mexico (NW). A similar approach will be evaluated to estimate emissions for other areas. An attempt will also be made to obtain venting rates from other large producers.
Emissions from fugitives were estimated for NMED by defining a typical well setup for oil, conventional gas and CBM wells. Typical well diagrams were developed to provide an estimate

of equipment counts for conventional wells. Emission rates were estimated for each gas well by combining the equipment counts and emission rates from EPA.

We propose to evaluate this approach for specific focus areas to improve existing estimates. The criteria for selecting areas to focus on will include anticipated growth or reduction in oil and gas exploration and production, and areas with different formation pressures to get a sense of how such pressures affect venting.

In the NW NM work, we did not estimate emissions for glycol dehydrators because it was not practical given the low field pressures in the San Juan Basin.   Any dehydration would be performed in gas plants and should therefore be accounted for in the point source inventory. For this effort, we propose to check the appropriateness of this assumption by reevaluating if field dehydration is performed in specific areas of interest.

f) Fugitive Dust Emissions

We will look at the feasibility of estimating dust emissions from vehicle traffic on unpaved road and for drilling wells. This can only be done if appropriate activity information and emission factors can be obtained. One method that we will look into is the use of satellite photos (such as those available from Google Earth) to determine those areas with relatively large numbers of unpaved roads associated with oil and gas production.

For this effort, we will evaluate the availability of data for estimating dust emissions from reentrained road dust, construction activities associated with drilling wells (i.e., road and well pad construction), and for new wells. We anticipate that much of this information may be difficult to obtain. Because this is a whole new area of work, and because we anticipate that large resources would be required for this effort, we will not likely be able to evaluate dust emissions in addition to the other emissions of interest. However, we will make suggestions on how the work could be performed.

3. TASK 2: CONTROL STRATEGY EVALUATION

Under this task, we will evaluate potential control technologies that can be applied to the sources of NOx, PM, SOx and VOCs as listed in Table 3-1.

Table 3-1. Control technology evaluations to be conducted.

Equipment	NOx	PM	SOx	VOC
Drill Rigs	x	x	X[2]	
Compressor Engines	x	X[1]		
CBM Engines	x	X[1]		
Tanks				x
Glycol Dehydration Units				x
Heaters	x			
Pneumatic Devices				x
Completion Flaring and Venting	x			x

[1] Development of Control Technology will depend on level of emissions
[2] SOx emissions will be a function of the sulfur content of fuels

We recognize that a great deal of work has been conducted to date evaluating potential controls for O & G sources. Available information and reports include documents developed for the EPA Natural Gas Star Program, Colorado's recent oil and gas control analysis, the Four Corners Air Quality Task Force, Argonne National Lab's Strategic Emissions Reduction Plan (SERP), and recent work by ENVIRON on retrofitting compressor engines in northeast Texas. Additional information that will be used in this task includes published reports on emission controls including EPA's Alternative Control Technique Documents for IC Engines, the E.H. Pechan & Associates Air Control Net Documentation, the California Air Resources Board (CARB) distributed generation regulation, as well as the CARB portable equipment registration program.

ENVIRON's work in this task will focus on identifying the effectiveness of these control strategies and technologies as well as the costs for implementing these controls. For each of the sources identified in Table 6-1 that are located in the basins where the 2002 emissions efforts are focused, we will identify the current baseline of controls (compared to uncontrolled emissions) as well as the control requirements that are currently in place for each state including current federal, tribal and state regulations and requirements that have been included by states under their permitting programs. We will also identify any controls requirements that are "in the works" or anticipated in the near future by the states. To the extent possible we will identify controls that go beyond regulation, for example some of the larger engines in the Durango area are all either lean-burn or have NSCR. This will include an assessment of which engines are covered under federal nonroad and/or stationary source rules. We will also consider fleet turnover, i.e., how rapidly the fleet of older uncontrolled engines can be expected to be replaced by newer cleaner engines. Once the current levels of controls have been identified, we will evaluate the potential for additional controls beyond current requirements. In evaluating the potential for additional controls, we will evaluate a range of viable control options. For each control option, we will evaluate the range of control efficiencies, the range of costs and cost-effectiveness and the potential for applying the controls to existing equipment (i.e., retrofit applications) versus new equipment. Finally, an estimate of the potential emission reductions (percent reduction) will be provided for each control option for each state. The results of this effort will therefore be a menu of potential control options for each state in each basin identified in Section 2.

For each control measure evaluated, a one- or two-page summary will be prepared that provides a description of the control measure, an assessment of feasibility (current and future), the range of control efficiencies, the range of costs and cost-effectiveness and the potential for applying the controls to existing equipment (i.e., retrofit applications) versus new equipment. We will also provide a summary table of all controls for each piece of equipment identified, and a summary table of the potential percent emission reductions for each control option for each state in each basin identified in Section 2.

4. TASK 3: 2018 EMISSIONS FORECASTS AND POTENTIAL CONTROL STRATEGIES BY STATE

The existing 2018 WRAP oil and gas emissions estimates were developed by projecting 2002 emissions based on a combination of production data and well count data. The dominant method used was to develop growth factors that were based on projecting 2002 oil and gas emissions based on the number of new oil, gas and possibly CBM wells anticipated, as provided in Resource Management Plans (RMPs). Where RMPs were not available, the Energy Information Administration's (EIA) regional production forecasts were used.

The proposed methodology for revising 2002 (and potentially 2005) emissions relies heavily on well count as a basis for estimating 2002 emissions. In order to maintain consistency with this methodology for projecting to 2018 emissions, production data needs to be converted to well count data. This will be done by developing a forecasted average production per well on a basin basis. This information will be derived from producers' information from the 2002 and 2005 calendar years, as well as future forecasts, and by examining the state OGC databases on a county basis. For compressor engines specifically, it will be necessary to estimate the percentage of wells that will have wellhead compression rather than centralized or lateral compression, as this contributes directly to the area source inventory. This is consistent with producer information which has indicated that in many mature fields in the WRAP region there is a trend of increasing number of wells (well count) but decreasing production, which necessitates more wellhead compression. The projected percentage of wells with wellhead compression and a projected production per well can be used to develop a growth factor for compressor emissions on the basis of well count, even in areas where only EIA forecasts of production are available. It should be pointed out that some emissions, such as fugitives, are a function of the number of items while some, such as compression, are a function of production and pressure. Based on available resources, our evaluation of fugitive VOC emissions will take into consideration these differences.

This task will require a focused study of the different areas on a basin basis using producer information. We will also evaluate selected older RMPs to determine the accuracy of previous predictions. If it is found that the older RMPs do not well predict 2002 (or 2005) well counts, alternate methodologies, such as EIA forecasts and production per well, will be used to determine well counts. We will include in the range of projection factors a scenario that uses the upper ranges of possible wells. We will also explore the impact of the under-prediction that has been common in RMPs and Environmental Impact Statements. We will review areas where we have recent well counts from state OGCs and compare those counts to the RMP forecasts and to the projection factors that we previously developed. In developing the updated factors, we will look at a range of estimates based on the information we obtain from assessing earlier predictions. Our analysis will include an evaluation of the production decline in several areas. Based on information received in preliminary discussions, even with increased levels of activity, production is declining or at best staying flat. This decline is expected to accelerate as current development opportunities are drilled out.

Once we have assessed the 2018 emissions projections, we will evaluate the potential reductions in emissions that can be achieved from the 2018 emission estimates based on the control levels identified in Task 2, Control Strategy Evaluation. We will recommend a control strategy that is a combination of the most promising controls based on feasibility and cost-effectiveness identified under Task 2. We will then estimate the emissions reductions that could be achieved in each western state if this control strategy were in place in the year 2018. For those states, outside the basins evaluated under Task 1, 2002 Emissions Inventory Improvements, we will apply the control factors developed for the basins evaluated with the exception that we will account for upcoming controls, if any, that have been adopted by states since the previous inventory, as well as controls “in the works”, if any.

Accordingly, the potential reductions in 2018 emissions for these other states will not reflect technology, if any, that has been applied beyond current control requirements in these states. However, it is assumed that such reductions will already be accounted for in the current 2002 Emissions Inventory.

5. OPTIONAL TASK 4: PROJECTION OF BASELINE EMISSIONS FROM 2002 TO 2005

There has been much development in oil and gas activity in certain basins in recent years. In the Phase I WRAP work, ENVIRON obtained detailed oil and gas wells production and activity data from state OGCs for the 2002 WRAP base year, and projected emissions from 2002 to 2018. In this Phase II work, ENVIRON will update the 2002 emissions estimates, update the 2002 to 2018 projection factors, and then develop revised 2018 projected emissions.

At this point in time, 2005 wells and production data are available from state OGCs, and could be used to estimate O&G area source emissions in 2005. If 2005 emissions were estimated, that would provide a more current year, with emissions matched to more current activity levels, from which to project the 2018 emissions.

If we were to estimate 2005 emissions, we would first revise the 2002 emissions using methods discussed in this work plan, and then scale up the revised 2002 county-level emissions to 2005 using county-level 2005/2002 OGC production and/or well count data. The choice of production or well count data for scaling would be made for each process separately, based on which type of data was the basis for the revised 2002 emissions calculations, although it is expected that the new methodology will use primarily well counts. In this way we would have a direct comparison of 2002 emissions using the old and revised methods.

As part of another project in the Four Corners region, we have already obtained the 2002 and 2005 county-level well count and production data for Arizona, Colorado, New Mexico, and Utah from the state OGCs. We would obtain the needed data from the remaining states with O&G production. (For California, where ARB provided the 2002 emissions directly, we would not estimate 2005 emissions.) There may be some counties without 2002 production or wells but with 2005 production and wells. In those cases we would grow the emissions by calculating the 2002 state average emissions per production unit or per number of wells, and then scale that to 2005 using the 2005 production or number of wells.

Since there have been changes in the oil and gas industry between 2002 and 2005, there is a potentially useful advantage in improving the 2018 projections by starting with 2005 as the baseline instead of 2002. However, the changes in the three years between 2002 and 2005 may or may not be as significant as the magnitude and uncertainty of the much larger industry changes expected by 2018. Although it is impossible to quantify that uncertainty, it is clear the 2005 estimates would be a more up-to-date starting point for projections out to 2018 than the 2002 estimates.

6. OPTIONAL TASK 5: SO_2 EMISSIONS FORECASTS FROM POINT SOURCES

A WRAP report was recently released on non-EGU SO2 Projections: "*2018 SO2 Emissions Evaluation For Non-Utility Sources*", October 2006 by Pechan. The purpose of this optional task is to revise the Pechan projections to reflect the 2018 production forecasts that ENVIRON would develop in Task, and also to reflect anticipated SO2 emissions controls using information that can be obtained from the producers.

The major source of SO_2 point source emissions from O & G operations in the WRAP region are natural gas processing plants, which are primarily located in Wyoming and New Mexico, but additionally in Colorado and Utah. Table 6-1 lists the gas plants in New Mexico and Wyoming with 2002 SO_2 emissions greater than 100 tons per year.

Table 6-1. NM and WY gas plants with 2002 SO_2 emissions greater than 100 tons per year.

State	Plant Name	SO_2 Emissions (tpy)
New Mexico	Maljamar Gas Plant	2,491
	Agave Gas Plant	2,099
	Indian Basin Gas Plant	2,040
	Eunice Gas Plant	1,330
	Jal No. 3	1,206
	Linam Ranch Gas Plant	928
	Artesia Gas Plant	838
	Monument Plant	837
	Denton Plant	295
	Dagger Draw Gas Plant	166
Wyoming	BP America – Whitney Canyon 6,291	6,291
	Burlington Resources – Lost Cabin 2,174	2,174
	Exxon Shute Creek I	1,818
	Hallwood Petroleum – Federal Packsaddle #1	971
	Chevron Carter Creek	686
	KCS Mountain Resources – Golden Eagle Flare	360
	Hiland Partners, LLC – Hiland Gas Plant	264
	Howell Petroleum Corp. – Elk Basin Gas Plant	181
	Union Pacific – Brady	144
	Hallwood Petroleum – Federal Packsaddle 1-24	141
	KCS Mountain Resources – Rushmore Flare	118
	Exxon – LaBarge Dehydration Facility	115

In order to improve the SO_2 emissions projections from these plants, detailed information will be collected from producers to determine current SO_2 emissions trends from 2002-2005 and any information from producers on expected development of new gas plants based on 2018 gas production forecasts. ENVIRON has already contacted Duke Energy and Agave Energy, both of whom indicated that current projections are not incorporating recent technological innovation to reduce SO_2 emissions. Specifically this includes the use of acid gas injection (AGI) technology which injects high-sulfur content gas or H_2S into deep wells to remove the sulfur from the production process. Agave Energy has indicated that, if properly functioning, this technology can achieve up to 90% reduction in SO_2 emissions. However, at the present the AGI systems installed by Agave and Duke have not yet achieved these control efficiencies.

The proposed methodology for improving the SO_2 emissions projections from these sources will include a thorough review of the Title 5 permits for the gas plants for detailed information on emissions prior to the installation of the technology, as well as after installation (if a second emissions analysis has been conducted). We anticipate being able to obtain these permits from state agencies. We will contact the owners and/or operations of these plants to determine if control technology has been installed or is planned for installation as well as the time frame when such control technologies will be effective. In addition, for a limited number of plants, producers will be contacted to provide detailed information on plant emissions prior to control technology installation and post installation. The producers will be asked to provide information on the potential for new plant development by 2018 given current gas production trends. Based on information from Agave Energy, it is not expected that any significant new plant development will be occur although this will be verified. This information from producers will be used to develop a production-based growth factor for SO_2 emissions from point sources that accounts for recent emissions control technology implementation, and an assumed penetration rate of the emissions control technology based on producer information about current trends.

7. SCHEDULE AND BUDGET

The schedule and deliverables for the tasks identified in this workplan are shown in the table below. This schedule will need to be somewhat flexible to accommodate obtaining information from major producers who will be contacted on an individual basis. It should be noted that some tasks are not dependent on each other and can be carried out concurrently. For example, the control technology evaluation will be ongoing wile awaiting detailed information from producers for the 2002 emissions inventory update.

Task	Milestone	Subtask	Due Date
1	Updated 2002 Emissions Inventory	Major producers' emissions inventory questionnaire distributed	November 15, 2006
		Producer information on activity by basin provided to ENVIRON	January 10, 2006
		Development of improved 2002 emissions inventory and memorandum to WRAP on preliminary findings	February 15, 2007
2	Update Baseline Emissions from 2002 to 2005	Development of 2005 baseline emissions from scale-up of 2002 improved inventory	February 22, 2007
3	Control Strategy Evaluation	Development of control strategies white papers. Summary of white papers in technical memorandum to WRAP	January 5, 2007
4	2018 Emissions Projections	2018 projection growth factors developed.	March 1, 2007
		Control strategy implementation scenarios for 2018 developed.	March 15, 2007
		Technical memorandum on 2018 emissions projections to WRAP	March 22, 2007
5	SO_2 Point Source Emissions Projections	Major gas plant operators contacted and questionnaire distributed	January 5, 2007
		Title 5 Permits obtained and analyzed	February 1, 2007
		Technical Memorandum on revised SO_2 point source projection factors to WRAP	February 8, 2007
6	Draft Final Report	Draft Final Report to WRAP for comments	April 1, 2007
7	Final Report		Two weeks after receipt of comments on draft report

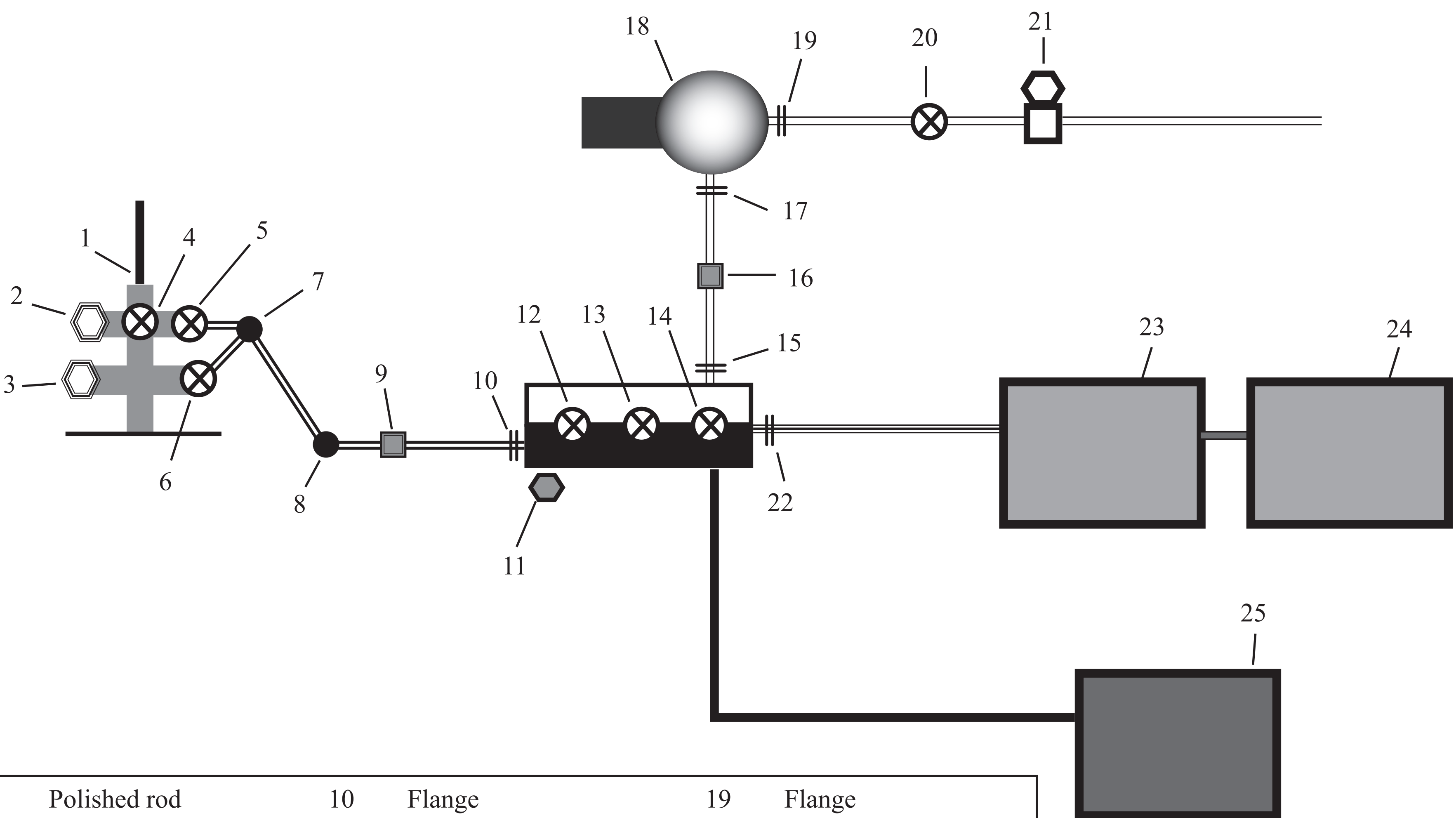
COST ESTIMATES FOR ADDITIONAL TASKS

ENVIRON estimates that optional Task 4, Updating Baseline Emissions from 2002 to 2005, will cost $5200. Costs for optional Task 5, Improvements to Point Source SO_2 Emissions in 2018, are estimated at $9700.

ATTACHMENT II

Typical Setup Diagrams for Oil, Gas, and Coalbed Methane Wells

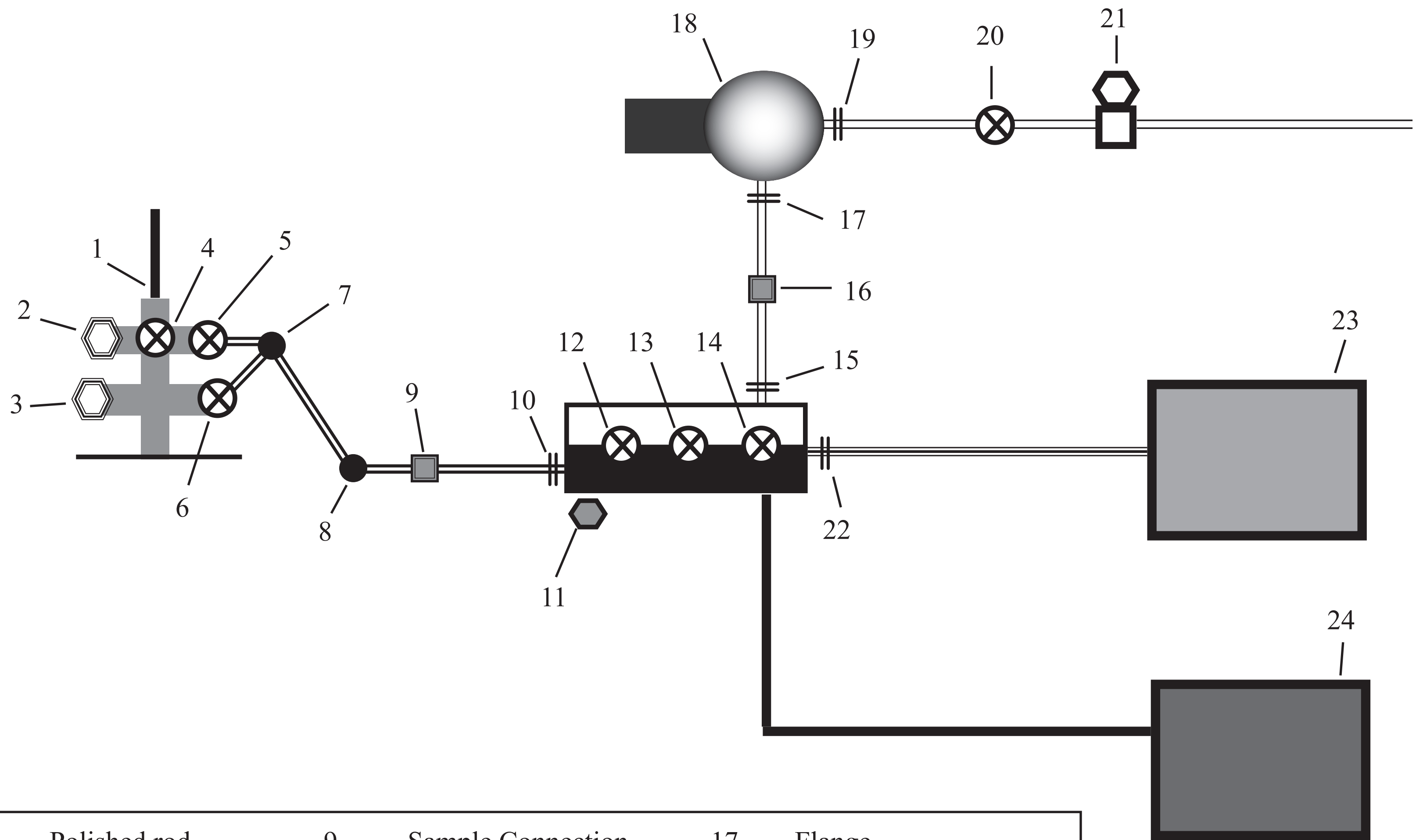
Oil Well - VOC and Minor NOx Sources



1	Polished rod	10	Flange	19	Flange
2	Pressure gauge	11	Separator heater	20	Relief valve
3	Pressure gauge	12	Separator dump valve	21	Meter
4	Master valve	13	Separator dump valve	22	Flange
5	Tubing flow valve	14	Separator dump valve	23	Oil Tank
6	Casing flow valve	15	Flange	24	Oil Tank
7	Connector	16	Sample Connection	25	Produced Water Tank
8	Connector	17	Flange		
9	Sample Connection	18	Compressor		

Note: Not drawn to scale.

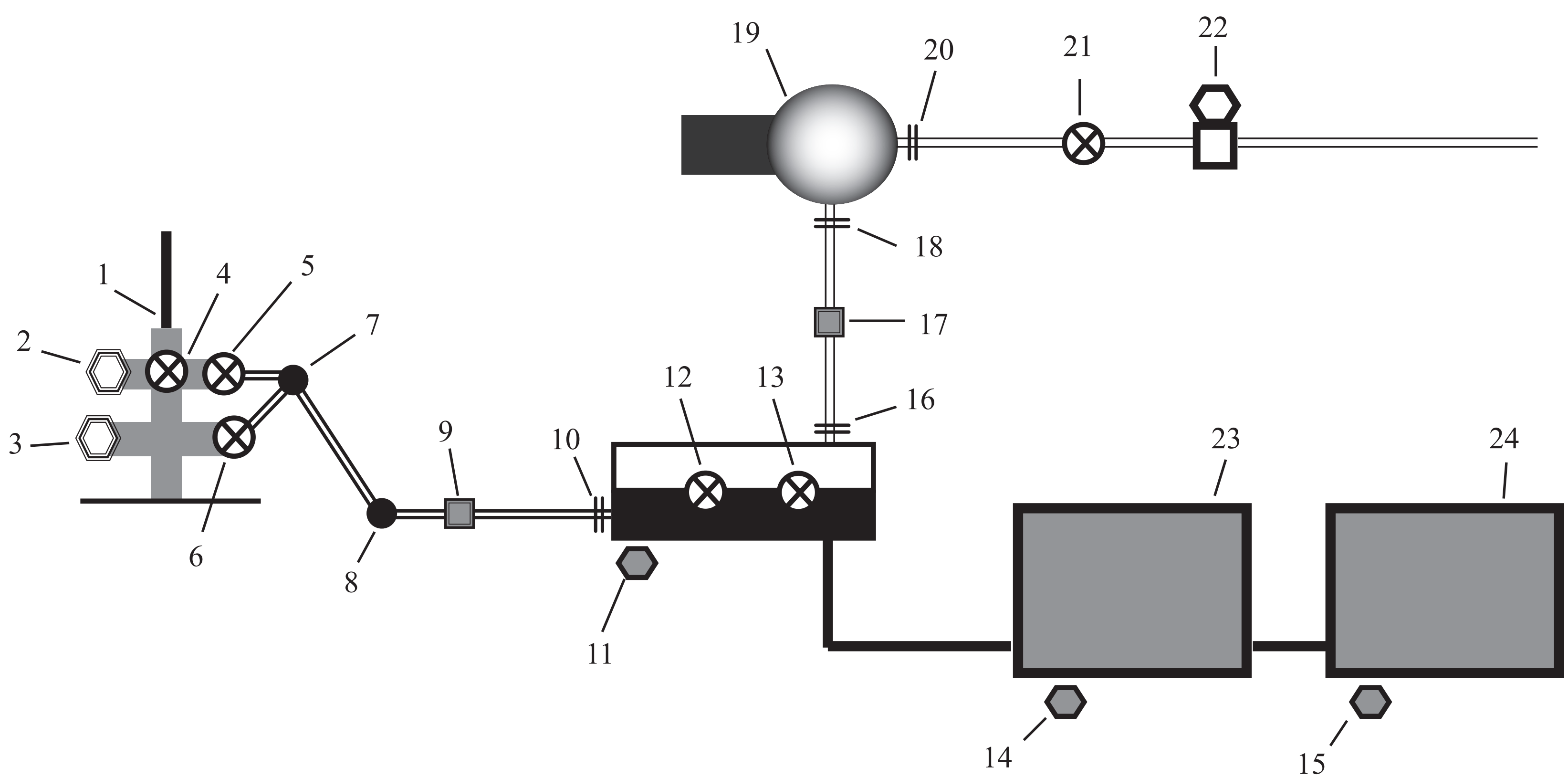
Gas & Condensate Well - VOC and Minor NOx Sources



1	Polished rod	9	Sample Connection	17	Flange
2	Pressure gauge	10	Flange	18	Compressor
3	Pressure gauge	11	Separator heater	19	Flange
4	Master valve	12	Separator dump valve	20	Relief valve
5	Tubing flow valve	13	Separator dump valve	21	Meter
6	Casing flow valve	14	Separator dump valve	22	Flange
7	Connector	15	Flange	23	Condensate Tank
8	Connector	16	Sample Connection	24	Produced Water Tank

Note: Not drawn to scale.

CBM Well - VOC and Minor NOx Sources



1	Polished rod	9	Sample Connection	17	Sample Connection
2	Pressure gauge	10	Flange	18	Flange
3	Pressure gauge	11	Separator heater	19	Compressor
4	Master valve	12	Separator dump valve	20	Flange
5	Tubing flow valve	13	Separator dump valve	21	Relief valve
6	Casing flow valve	14	Tank heater	22	Meter
7	Connector	15	Tank heater	23	Produced Water Tank
8	Connector	16	Flange	24	Produced Water Tank

Note: Not drawn to scale.