**Final Report**

# RECOMMENDATIONS FOR IMPROVEMENTS TO THE CENRAP STATES' OIL AND GAS EMISSIONS INVENTORIES

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# TABLE OF CONTENTS

Page

## APPENDICES



## TABLES

## FIGURES

# EXECUTIVE SUMMARY

CENRAP has identified the need to improve the oil and gas area source inventories for the 2002 base year and 2018 future year for the entire CENRAP region, encompassing the oil- and gas-producing states of Texas, Louisiana, Oklahoma, Arkansas, Kansas and Nebraska. This is being driven by the high levels of oil and gas production activity that occur at hundreds of thousands of individual well sites, the large fleet of equipment that supports this activity, and the potential for this equipment to significantly contribute to emissions of NOx, VOC, SOx, greenhouse gases (GHG) and other pollutants in the region. Previous CENRAP and state inventories have been limited by data availability and the geographic specificity of this data. Often these inventories have relied on broad, regional assumptions to generate oil and gas area source emissions inventories. Following the work of ENVIRON, under contract to the Western Regional Air Partnership (WRAP) in generating the WRAP Phase I and II, and the joint Phase III project with the Independent Petroleum Association of Mountain States (IPAMS), CENRAP has contracted with ENVIRON to provide improved input information and methodology descriptions to update these inventories.

This work consisted of three principal tasks:

1. Identification of major CENRAP basins: the objective of this task was to generate oil and gas production statistics for all of the major geological basins in the CENRAP domain to determine which are the “major” basins. Major basins are those basins ranked highest by production of gas, oil or by active well counts.
2. Literature review and limited industry survey: the objective of this task was to gather input data used to calculate emissions from a wide variety of source categories associated with oil and gas exploration, production, transmission and gathering activities by reviewing published literature and studies on oil and gas emissions and equipment, and by conducted a limited industry survey to gather information about specific source categories in specific basins.
3. Develop recommendations: the objective of this task, and the subject of this report, was to synthesize the information gathered in Tasks 2 and 3 and recommend input data and methodologies to improve CENRAP’s oil and gas area source inventories for the 2002 base year and 2018 future year projections.

These tasks and their results are described in detail in this report, and the accompanying recommendation data matrix spreadsheets.

## Task 1: Identification of Major CENRAP Basins

ENVIRON obtained and analyzed databases of oil and gas production statistics from all six CENRAP states with significant oil and gas production, and obtained state-wide oil and gas production totals from all other CENRAP states. The determination was made to focus on the states of Texas, Louisiana, Oklahoma, Arkansas, Kansas and Nebraska because these states collectively represent the overwhelming majority of oil and gas production and active wells in the CENRAP region.

The databases were obtained from each state's oil and gas conservation commission (OGCC) or equivalent agency. The databases required significant work to remove missing, incorrect or inconsistent data, and to summarize the data for 2002 only, in a format that could be used to determine the production statistics of interest. The production statistics that were estimated in this analysis are:

- Gas production
- Oil production
- Condensate production (if available)
- Active well counts (by well type if available)
- Drilling event (spud) counts

These production statistics were determined for each state, and then geographic information system (GIS) analysis was used to intersect the spatially allocated statistical information with the boundaries of geologic basins to determine basin-level statistics. This was done for each state and combined where basin boundaries crossed state lines. The resulting oil and gas statistics summary from Task 1 are presented in Table ES-1.

**Table ES-1**. 2002 gas production, oil production, active well counts and spud counts for all basins in the CENRAP domain.

| Basin | Gas Production [MCF] | Oil Production [bbl] | Active Well Count | Spud Count |
|---|---|---|---|---|
| Anadarko Basin | 1,732,269,135 | 40,279,230 | 88,406 | 2,327 |
| Arkoma Basin | 364,833,847 | 3,019,091 | 12,401 | 739 |
| Bend Arch-Ft. Worth Basin | 321,056,553 | 24,156,879 | 106,173 | 1,662 |
| Cambridge Arch-Central Kansas Uplift | 6,442,698 | 14,649,639 | 10,366 | 387 |
| Cherokee Platform | 31,040,321 | 16,693,567 | 33,779 | 862 |
| Denver Basin | 1,192,111 | 1,321,300 | 1,288 | 11 |
| East Texas Basin | 980,666,377 | 23,944,407 | 33,453 | 1,159 |
| Forest City Basin | 415,029 | 946,580 | 5,850 | 131 |
| Louisiana-Mississippi Salt Basins | 391,332,732 | 13,146,248 | 34,805 | 63 |
| Marathon Thrust Belt | 63,294,963 | 56,723 | 278 | 15 |
| Nemaha Uplift | 27,773,241 | 8,419,664 | 11,913 | 249 |
| Ozark Uplift | 48,946 | 0 | 5 | 0 |
| Palo Duro Basin | 31,360,922 | 6,215,265 | 2,556 | 48 |
| Permian Basin | 679,260,325 | 256,544,364 | 113,598 | 2,957 |
| Salina Basin | 0 | 227,996 | 247 | 3 |
| Sedgwick Basin | 24,983,651 | 3,196,023 | 3,455 | 137 |
| Southern Oklahoma Basin | 60,355,759 | 18,586,235 | 24,651 | 349 |
| Western Gulf Basin | 3,410,532,407 | 100,096,887 | 108,403 | 2,417 |

From these summary statistics, the following eleven basins were identified as the "major" oil and gas production basins in the CENRAP region because they collectively represent greater than 95% of production of oil, production of gas, and active well counts:

- Anadarko Basin
- Arkoma Basin
- Bend Arch-Fort Worth Basin
- Cambridge Arch-Central Kansas Uplift
- Cherokee Platform
- East Texas Basin
- Louisiana-Mississippi Salt Basins
- Nemaha Uplift
- Permian Basin
- Southern Oklahoma Basin
- Western Gulf Basin

Recommendations for emissions calculations and specific input data for those calculations are provided for these specific basins, based on this analysis, in the report.

**Task 2: Literature Review and Limited Industry Survey**

This task required gathering information obtained from a review of relevant literature and published studies on emissions, processes and equipment used in oil and gas exploration and production activities, as well as development of a limited survey on specific source categories that was distributed to major oil and gas companies operating in the CENRAP region.

ENVIRON reviewed a wide range of published studies and reports on quantifying oil and gas emissions through analysis of equipment and processes in the field. The literature review included the WRAP studies, authored by ENVIRON, which developed the methodologies for estimating some of the oil and gas area source categories that had not been previously inventoried. The reports and studies that were selected for review in this analysis were analyzed for their applicability to the CENRAP inventories. The specific criteria used to evaluate literature reviewed in this task included:

1. <u>Geographic scope</u>: The most important criterion applied to determine the applicability of a literature source was the geographic scope which the study or report covers. Since production characteristics and the composition of the produced gas and oil vary widely from basin to basin, these regional differences can affect the usage of particular equipment and would necessarily affect the development of oil and gas emissions inventories for a particular basin. To the extent possible, data from regionally applicable studies were used to gather useful input data for emissions calculations.
2. <u>Age of study</u>: It was determined that older studies may not well represent the equipment and emissions characteristics in use in the oil and gas industry in the past decade, and that newer studies are more relevant and applicable to this task. To the extent possible this criterion was applied to the selection of specific data from some of the studies and reports.
3. <u>Consistency of data with other sources</u>: Data consistency was used as a QA/QC tool to evaluate the usefulness and applicability of data extracted from all of these studies and reports. Data were reviewed to be consistent both with other studies, and with detailed information collected by ENVIRON as part of the development of oil and gas inventories in the western states.

The data obtained from the literature reviewed, with the above criteria applied, were compiled into a master data matrix that was then supplemented by data obtained as part of the limited industry survey task. These data form the basis of the recommended input data for calculating emissions from a variety of oil and gas source categories.

The limited industry survey was conducted in anticipation of not being able to find information on all of the needed input parameters to estimate emissions from a wide variety of source categories. The survey asked for basin-level representative data on specific major oil and gas NOx and VOC source categories (which are also the major $SO_2$ source categories). It is ENVIRON's experience that only the oil and gas companies can provide highly detailed and highly geographically-specific data on equipment, configuration, usage, processes, and emissions factors to generate the most accurate emissions estimates. For this task ENVIRON relied on its contacts with the oil and gas industry through the WRAP work to survey specific major companies operating in the CENRAP region. A survey questionnaire was developed that asked for data on the following major oil and gas source categories:

- Drilling rigs
- Compressor engines
- Artificial lift engines
- Heaters
- Condensate and Oil tanks
- Fugitive emissions
- Pneumatic devices
- Completion/recompletion venting and well blowdowns

These source categories were determined to be the top contributors to NOx, VOC and $SO_2$ emissions from ENVIRON's development of the detailed Phase III inventories for the western regional U.S. These are also source categories with high basin-to-basin variability and thus would benefit most from industry data on their usage in specific basins. Table ES-2 shows the companies that ENVIRON considered and/or contacted for this survey process, and the outcome of the survey outreach effort.

**Table ES-2.** Summary of companies contacted as part of the survey process including their regions of operation and the status of their responses to the survey.

| Company | Geographic Area of Major Operations (by basin) | Survey Sent (Y/N) | Survey Received (Y/N) |
|---|---|---|---|
| BP America | Anadarko, Arkoma, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, East Texas, Marathon Thrust Belt, Palo Duro, Permian, Sedgwick, Western Gulf | Y | N |
| Conoco-Phillips | Anadarko, Bend Arch-Ft. Worth, East Texas, Marathon Thrust Belt, Nemaha Uplift, Palo Duro, Permian, Sedgwick, Western Gulf | Y | N |
| Chevron | Southern Oklahoma | Y | N |
| Anadarko Petroleum | Anadarko, Arkoma, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, East Texas, Permian, Southern Oklahoma, Western Gulf | Y | Y |

| Company | Geographic Area of Major Operations (by basin) | Survey Sent (Y/N) | Survey Received (Y/N) |
|---|---|---|---|
| Encana USA | Bend Arch-Ft. Worth, East Texas, Permian, Western Gulf | Y | Y |
| Devon Energy | Anadarko, Arkoma, Bend Arch-Ft. Worth, East Texas, Louisiana-Mississippi Salt, Nemaha Uplift, Permian, Sedgwick, Western Gulf | Y | Y |
| Noble Energy | Anadarko, Arkoma, Cambridge Arch-Central Kansas Uplift, Cherokee Platform, East Texas, Louisiana-Mississippi Salt Basins, Nemaha Uplift, Permian, Southern Oklahoma, Western Gulf | Y | Y |
| EOG Resources | Anadarko, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, East Texas, Nemaha, Permian, Southern Oklahoma, Sedgwick | Y | N |
| XTO | Anadarko, Arkoma, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, Cherokee Platform, East Texas, Nemaha Uplift, Palo Duro, Permian, Southern Oklahoma, Western Gulf | Y | N |
| ExxonMobil | Arkoma, Louisiana-Mississippi Salt Basins | N | – |
| Occidental Petroleum | Permian | N | – |
| El Paso Corporation | Louisiana-Mississippi Salt Basins | N | – |
| Petro-Chem Operating | Louisiana-Mississippi Salt Basins | N | – |

Table ES-2 shows that not many companies responded with completed surveys, and that some companies that ENVIRON had specifically targeted for the survey outreach (such as BP America) were not willing to participate in this process. Despite the small number of completed surveys, these surveys did form part of the data gathered in the master data matrix and used as recommended inputs in this analysis.

**Task 3: Recommendations**

The majority of this analysis focuses on providing detailed methodologies to estimate base year 2002 emissions from the major oil and gas area source categories, both for individual sources and for basin-level emissions totals. This input data includes the fractional usage of equipment at well sites, equipment characteristics such as size, annual usage and emissions factors, process information such as venting rates and well component configurations, and chemical composition analyses used to determine pollutant emissions rates. These input data and methodologies for emissions estimation are provided in this report for the following major oil and gas source categories:

- Wellhead Compressor Engines
- Lateral Compressor Engines
- Artificial Lift Engines (Pumpjacks)
- Drilling Rigs

- Heaters
- Flaring
- Oil Tanks (Flashing and Working & Breathing Losses)
- Condensate Tanks (Flashing and Working & Breathing Losses)
- Dehydrators
- Completion Venting
- Well Blowdowns
- Fugitive Emissions
- Pneumatic Devices

The data are also provided in detailed spreadsheets that accompany this report, and for some source categories the detailed data are provided only in the accompanying spreadsheets. These recommendations can be used directly to update the 2002 oil and gas area source inventories for all major CENRAP basins, and can be extended to include all CENRAP basins.

It is important to note that this is a broad, regional study aimed at helping CENRAP improve their domain-wide oil and gas area source emissions. The broad scope of the geographic domain covered in this work necessarily limits the ability to generate highly detailed and highly spatially-resolved input data and recommendations. This has been ENVIRON's experience in developing the WRAP regional inventories. Where appropriate, the analysis indicates caveats associated with the use of the input data and the assumptions that were made to arrive at the recommendations. If in the future CENRAP has access to more detailed information from local studies, or a further industry survey effort, these recommendations should be revisited and revised as appropriate.

Recommendations have also been developed for scaling emissions from 2002 to 2018. The projection methodology focuses on developing growth or decline factors for activity, scaling the emissions of specific source categories by specific growth or decline factors, and then controlling these emissions to account for federal and state regulations that may affect future emissions. Because of the lack of project-specific growth estimates for individual oil and gas developments in the CENRAP region, the 2018 growth/decline factors rely on broad regional estimates derived from the Energy Information Administration's Annual Energy Outlook (AEO). This is an economic analysis that is used to predict future gas and oil production in regions of the continental U.S. and can be used to predict drilling activity.

Methodologies for developing control factors to represent future impacts of federal or state regulations are also presented in this work. The methodologies cover all federal and state regulations of which ENVIRON is aware, but it should be noted that regulations covering oil and gas area sources were only found for the State of Texas. The report does not provide the control factors, but rather indicates how these control factors can be derived for each state.

# INTRODUCTION

The last decade has seen a tremendous growth in oil and gas exploration and production throughout the continental United States, but centered primarily on the Rocky Mountain states, many of the central states, and the Gulf of Mexico. In 2002, the states comprising the Central States Regional Air Partnership (CENRAP) – Texas, Louisiana, Oklahoma, Arkansas, Kansas, Nebraska, Missouri, Iowa, and Minnesota – had a combined gas production total of approximately 8.5 trillion cubic feet and a combined oil production total of approximately 615 million barrels (EIA, 2008). This represents nearly 43% of total U.S. gas production and nearly 30% of total U.S. oil production.

In order to support this level of oil and gas production, the oil and gas companies employ a large fleet of equipment used in a wide variety of oil and gas exploration, drilling, production, processing and transmission activities. This equipment, much of which has traditionally been classified as an area source, has not been well inventoried in the past (Russell, et al., 2005; Bar-Ilan, et al., 2007) and can represent a substantial source of many criteria pollutants (NOx, CO, SOx, VOC) as well as greenhouse gas (GHG) emissions for these CENRAP states.

Some of the CENRAP states have made efforts to inventory these emissions sources in the past (Reid, et al., 2008; Pendleton, et al., 2008), but CENRAP has identified the need to improve these inventories for both the baseline year of 2002 and the future year of 2018. These inventories relied on broad, regional data to generate emissions estimates per unit of production, and these emissions estimates were then scaled to the state level by using total state production statistics. While this approach is useful in generating some emissions estimates where these sources had never been inventoried before, the broad-based activity and equipment assumptions used in creating these emissions inventories do not apply to all major regions of oil and gas activity. In the past work of ENVIRON in developing oil and gas emissions inventories for the Rocky Mountain states (Russell, et al., 2005; Bar-Ilan, et al., 2007; Bar-Ilan, et al. 2008; Pollack, et al., 2006), it has been observed that oil and gas activity is best grouped on the basin level. Basins are large-scale oil and gas geologic formations in which the exploration and production activities are relatively consistent across the basin (USGS, 2008). The basin thus provides a geographic unit to use as the basis for generating a regional emissions inventory. This report summarizes the input data and methodology needed to improve the CENRAP regional oil and gas area source emissions inventory at the basin level. Considering the previous inventory efforts of CENRAP at the regional scale, the work presented here provides an opportunity to increase the types of oil and gas source categories considered to be major contributors to NOx, VOC and SOx emissions beyond those originally considered in past inventory efforts.

## OBJECTIVES

CENRAP has identified the need to improve the emissions inventory for oil and gas area sources for each of the CENRAP states with major oil and gas production and activity. The first step in improving these state-level oil and gas emissions inventories is to obtain improved information on equipment, activity, configurations, and production statistics to feed into updated inventory calculations. Obtaining this information and providing recommendations on data to use are the objectives of this study. Specifically the objectives of this study are:

1. Identify major CENRAP oil and gas basins and their production statistics: For this task ENVIRON was to identify major oil and gas basins within the boundaries of the CENRAP states by obtaining each state's oil and gas production statistics and intersect them with the boundaries of basins as defined by the USGS. The resulting data would be basin-level summaries of oil (condensate) production, gas production, active well counts by well type, and drilling event (spud) counts. This was to allow for the identification of those basins in the CENRAP domain that make up the majority of oil and/or gas production and are therefore considered "major" basins.

2a. Gather information on equipment and activity from a literature review: For this task ENVIRON was to compile a list of studies, reports and other literature, including those reports specifically identified by CENRAP, to review for possible usefulness in developing an improved oil and gas area source inventory. Information obtained from the literature would include, if possible, equipment counts, emissions factor and activity factors of this equipment (e.g., load factors, annual hours of operation, etc.) and gas composition data. Where possible this literature would be specific to a particular basin. ENVIRON was to use our extensive work in developing oil and gas emissions inventories to expand on the list of studies and reports recommended by CENRAP to include those additional studies which may provide useful data.

2b. Gather supplemental information on equipment and activity from a limited industry survey: For this task ENVIRON was to supplement the information gathered from the literature review, which was likely to not be specific to individual basins except in limited some limited studies, with detailed basin-specific data on operations obtained from surveying companies operating in these basins. ENVIRON would draw on its extensive contacts among the oil and gas industry to survey the major companies, identified by proportional ownership of production in each major basin. The survey was to ask for targeted information on the major oil and gas source categories to aid in improving the inventories for these source categories in the major basins.

3. Provide recommendations for data and emissions estimations for 2002 and 2018: For this task ENVIRON was to summarize the findings of Tasks 1 & 2 above and provide recommendations for both the methodology and input data to be used to estimate emissions from each major oil and gas source category for each of the major basins identified. The recommendations would also include a description of the methodology to project 2002 baseline emissions to 2018 and recommendations of where projection data should be obtained.

## TEMPORAL & GEOGRAPHIC SCOPE

This inventory improvement project considers a base year of 2002 for purposes of obtaining data on activity and equipment in the field, and for all analysis of production statistics. All data requested from companies that were surveyed were for these companies' activities in the calendar year 2002. Similarly, all well count and production data for all basins obtained as part of Task 1 were for the calendar year 2002. It is assumed that all emissions from all source categories are evenly distributed throughout the year –no seasonal allocation fractions are derived because the vast majority of all oil and gas area source equipment operates throughout the year. All methodology descriptions presented in this report are for estimating emissions on an annual basis.

A future year of 2018 is considered for purposes of projecting emissions. The methodology for conducting the emissions projections requires the development of scaling factors which are used to project emissions to the future year. These scaling factors are specific to the future year of the projection and this work therefore considers only the 2018 future year.

The geographic scope of this inventory is the CENRAP domain, which wholly includes the states of Texas, Louisiana, Arkansas, Oklahoma, Kansas, Nebraska, Missouri, Iowa and Minnesota. As is shown in the discussion of oil and gas production statistics below, Missouri, Iowa and Minnesota do not have substantial (or have no) oil and gas activity and are thus not considered as part of the geographic scope of this work. Within the states of Texas, Louisiana, Arkansas, Oklahoma, Kansas and Nebraska the USGS definitions are used to define the boundaries of the major oil and gas geological basins. The complete list of basins is:

- Western Gulf Basin
- Permian Basin
- Marathon Thrust Belt
- Bend Arch-Fort Worth Basin
- East Texas Basin
- Louisiana- Mississippi Salt Basins
- Palo Duro Basin
- Southern Oklahoma Basin
- Arkoma Basin
- Cherokee Platform
- Anadarko Basin
- Sedgwick Basin
- Nemaha Uplift
- Salina Basin
- Cambridge Arch-Central Kansas Uplift
- Denver-Julesburg Basin

As is detailed in the discussion of oil and gas production statistics below, not all of these basins are considered major basins of oil and gas activity, but their production statistics are provided and thus they are considered part of the geographic scope of this work.

Figure 1 shows a map of the CENRAP domain with state and basin boundaries demarcated, as well as the location of oil and gas wells in 2002.

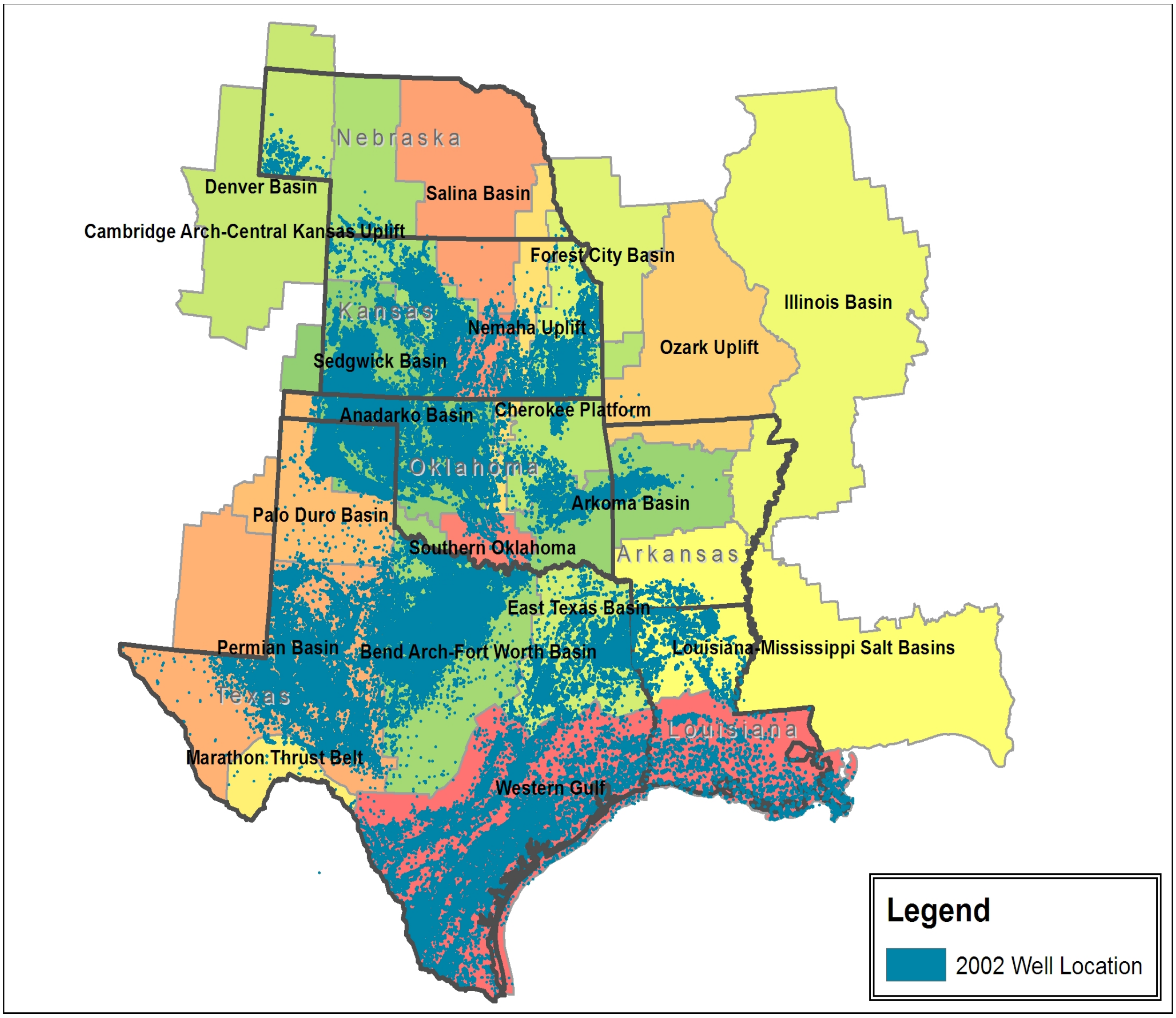


**Figure 1.** The CENRAP geographic domain including state and basin boundaries, overlaid with 2002 oil and gas well locations.

## POLLUTANTS CONSIDERED

This work considers the following major pollutants from oil and gas area sources, per the CENRAP scope of work for this project:

- NOx
- VOC
- CO
- SOx
- $PM_{10}/PM_{2.5}$
- $H_2S$
- $CO_2$
- $CH_4$

It should be noted that oil and gas exploration and production, processing, and transmission activities are not significant sources of PM emissions. $H_2S$ and $CH_4$ emissions are only emitted as a result of direct venting of produced gas that contains these two species. $CH_4$ is a major component of produced gas while $H_2S$ is a minor species that is present in some locations. To the extent possible information is presented on the $H_2S$ content of gas but it should be noted that this information is not extensive or detailed at the level of the individual oil or gas field. VOC emissions are either the result of direct venting of produced gas that contains VOC species, or from combustion emissions. All other pollutants above are combustion-generated.

## TASK 1: BASIN IDENTIFICATION

As the first task in the project, ENVIRON obtained and analyzed 2002 oil and gas production and well statistics for each of the CENRAP states in order to identify the extent of oil and gas activity in each state, and further to quantify the production and well statistics for all of the basins in the CENRAP domain to identify the major basins of oil and gas activity. This task required obtaining detailed oil and gas data, usually in the form of electronic databases, maintained by the oil and gas conservation commissions (OGCC, or equivalent) of each state in the CENRAP domain. It should be noted that these databases vary greatly with respect to the detailed information tracked by each OGCC, the format of the database, and ultimately the oil and gas statistical information available. Early in the development of this task, ENVIRON contacted IHS Corporation, which offers a commercially available database of oil and gas statistics for all of the United States of extremely high quality. It was determined that the access cost of using the IHS database (also known as the P.I. Dwight database) was beyond the budget and resources of this project, so the work described here is ENVIRON's analysis of the detailed oil and gas databases obtained from each state's OGCC or equivalent, with the limitations of each database described in detail below.

Prior to obtaining and analyzing each state's oil and gas statistics, ENVIRON investigated the total oil and gas production from all of the states in the CENRAP domain to determine if some states had little or no oil and gas activity. This would allow for the elimination of these states from the detailed analysis. The state-by-state oil and gas production totals were obtained from the Energy Information Administration state summary database (EIA, 2008) and are presented in Table 1.

**Table 1.** 2002 total oil and gas production by state for each state in the CENRAP domain.

| State | Oil Production [bbl] | % of Total CENRAP Oil Production | Gas Production [MCF] | % of Total CENRAP Gas Production |
|---|---|---|---|---|
| Minnesota | 0 | 0% | 0 | 0% |
| Iowa | 0 | 0% | 0 | 0% |
| Missouri | 93,000 | 0.02% | 0 | 0% |
| Nebraska | 2,779,000 | 0.45% | 1,188,000 | 0.01% |
| Kansas | 32,721,000 | 5.3% | 454,901,000 | 5.3% |
| Oklahoma | 66,642,000 | 10.8% | 1,581,606,000 | 18.6% |
| Arkansas | 7,345,000 | 1.2% | 161,871,000 | 1.9% |
| Texas | 411,985,000 | 67.0% | 5,084,012,000 | 59.7% |
| Louisiana | 93,476,000 | 15.2% | 1,226,613,000 | 14.4% |
| **CENRAP States Total** | **615,041,000** | **100%** | **8,510,191,000** | **100%** |
| **CENRAP States Total Production as Percentage of U.S. Total** | **29.3%** | | **42.8%** | |

Table 1 shows that oil and gas production activity in the states of Minnesota, Iowa, and Missouri is negligible, and therefore these states are not included further in any of the oil and gas production statistics analysis, or in the literature review or survey information summary portions of this project.

For the remainder of the CENRAP states with significant oil and gas production – Texas, Louisiana, Oklahoma, Arkansas, Nebraska and Kansas – the databases of oil and gas production and well statistics for each state were obtained from the states' respective OGCC or equivalent. Separately, definitions of the geographic boundaries of the major geological basins were obtained from the USGS (USGS, 2008) and were analyzed using Geographic Information Systems (GIS) tools to intersect the boundaries of the basins with the production and well statistics from all of the CENRAP states. Below are detailed descriptions of the methodologies used to analyze each state's oil and gas statistics data.

**Oklahoma**

Oklahoma historical well-level monthly gas production data and other well information were obtained from the Oklahoma Corporation Commission (OCC). These well-level data included owner/operator name, location of the gas well (latitude and longitude), purchaser, formation, lease number, and volume of gas production per month. The data were imported into a Microsoft ACCESS database so that querying and database analysis could be conducted as needed. The data were cleaned by removing well records with zero production in order to estimate active well counts only. Then basin boundaries were intersected with well locations to determine well counts in each basin in the state, as well as gas production in each basin in the state.

Oil production has not been tracked by the Commission for several years, and is not available from the database. Since the OCC does not track detailed oil production or maintain a database of oil wells, ENVIRON contacted OCC to find out how 2002 specific state-wide oil production data by well might be obtained. OCC suggested contacting two private commercial firms for oil production data in Oklahoma. However, both of these private databases would require access fees beyond the budget and resources of this project.

The alternative approach used was to obtain county-level oil production estimates and allocate these to the basins in which the counties are located. It should be noted that this approach is only accurate if basin boundaries align with county boundaries exactly. Therefore, the first step in determining oil production was to conduct a GIS analysis to intersect county and basin boundaries for Oklahoma. It was determined from this analysis that county boundaries align exactly with USGS-defined basin boundaries, as shown in Figure 2 (i.e. no county is sub-divided into more than one basin). 2002 county-level oil production was obtained from the Oklahoma Department of Environmental Quality, and basin total oil production was determined by summing county total oil production for each county located in the basin.

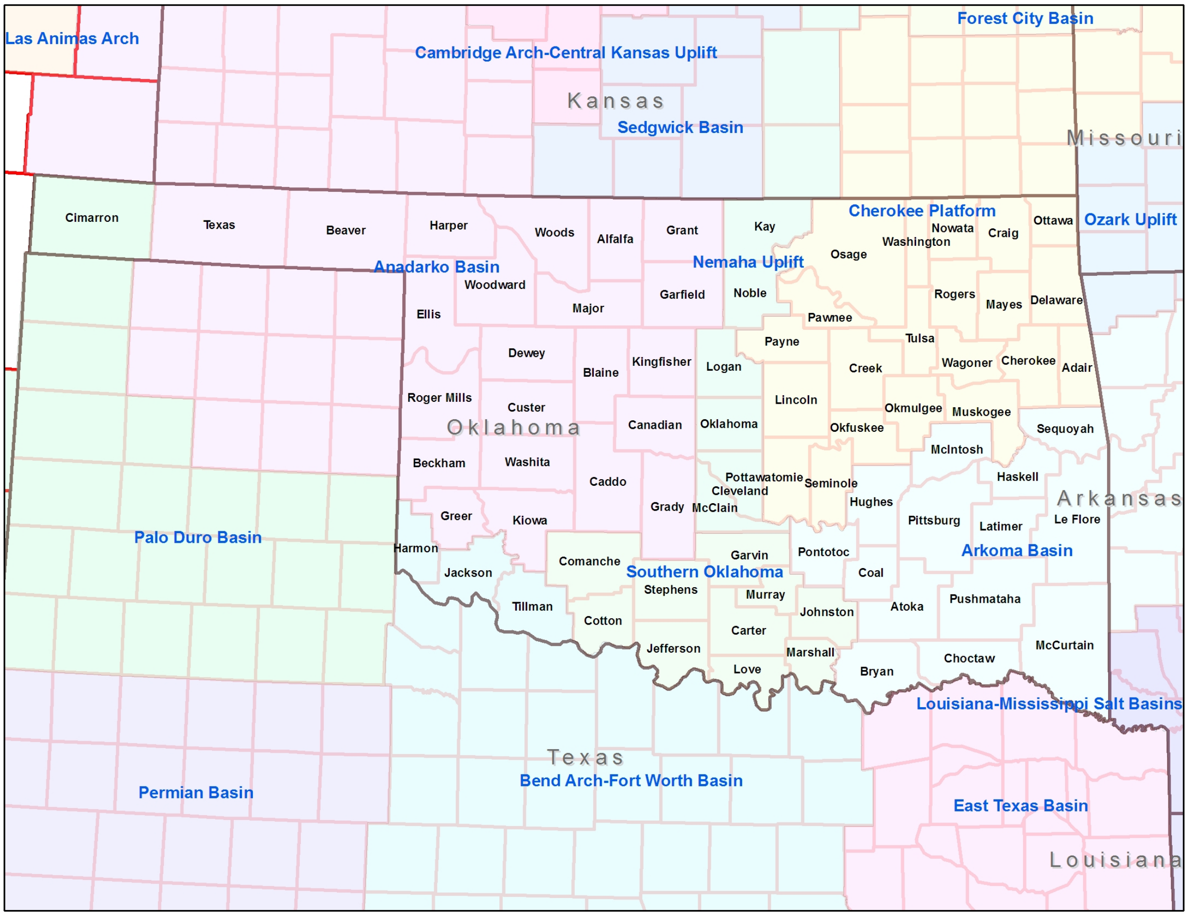


**Figure 2.** Map of Oklahoma showing exact alignment between county boundaries and the boundaries of the basins in the state.

Because of the unavailability of oil production data except at the broad county level, the data presented here does not contain a count of active oil wells in the state. Due to the level of oil production in Oklahoma, it is strongly recommended that any future analysis by CENRAP consider the use of commercial databases to obtain detailed well-level data on the active oil wells in the state.

Spud counts for 2002 were estimated using well completion dates provided in the Oklahoma oil and gas database. The well records having completion dates between January 1$^{st}$, 2002 and December 31$^{st}$, 2002 were selected as spud events for 2002. 2002 spud events were spatially allocated to the basin level using ARC/GIS. It should be noted that this would only represent spuds of gas wells, since OCC does not track oil well information.

Specifically, the following database analysis steps were performed to calculate oil and gas statistics by basins and counties:

1. Well-level gas production data was obtained from the OCC for the calendar year of interest.
2. The data was cleaned up by removing well records with no gas production.
3. Monthly production data was totaled to calculate annual production by wells.

4. Basin-level production and well counts – The USGS-defined basin boundaries were intersected with well locations to determine well counts in each basin in the state, as well as gas production in each basin in the state, using ARC/GIS.
5. County-level production and well count – Each well record in the OCC data file had an associated county FIPS code. The well data was linked with a county lookup table. Gas production and well count was summed by county.
6. Spud-counts – Spud counts for 2002 were estimated using well completion dates provided in the OCC oil and gas database. The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud events for 2002. 2002 spud events were spatially allocated to the basin using ARC/GIS. The county code associated with a well record was used to obtain spud count by county.

**Kansas**

A master database of oil and gas wells was obtained from the Kansas Geological Survey (KGS). KGS does not maintain oil and gas production data by lease/wells and therefore well data could not be linked to production data. However county level production data was obtained for the calendar year 2002 from KGS. As in the case of Oklahoma, Kansas county boundaries align exactly with USGS-defined basin boundaries, as shown in Figure 3. Basin level production was obtained by summing corresponding county-level production for all counties located within the boundaries of each basin in Kansas.

In order to estimate active well count by basin, a methodology was developed to determine the status of wells in 2002 from the master oil and gas wells database. Wells producing in 2002 were estimated by adding wells with valid completion dates and no plugging dates, or plugging dates after January 2002. If a data record was encountered with a workover code, this was not counted towards a unique active well but assumed to be a workover of a well already counted with the original unique API number. A certain percentage of older wells that were plugged do not have a plugging date listed in the KGS database. In this case, the date of completion of the well was determined from the database and if the well was completed more than 25 years before 2002 (in 1977 or earlier) it was assumed to be plugged and no longer an active well. This choice of well age cutoff was based on ENVIRON's previous experience examining the typical lifetime of a gas or oil well in the Rocky Mountain States, as well as specific data received from operators with active wells in Kansas. Service wells were also not included in the active well count. Service wells are those with a well status of "EOR," "SWD," or "WATER" indicating that they are enhanced recovery, water, or saltwater disposal wells which are not expected to have the same types of traditional gas and oil well equipment present. Therefore these wells should not be considered for use in emissions estimations that are based on well count. Dry holes (wells) with "D&A" status were not included because they were assumed to be depleted or never having produced either oil or gas.

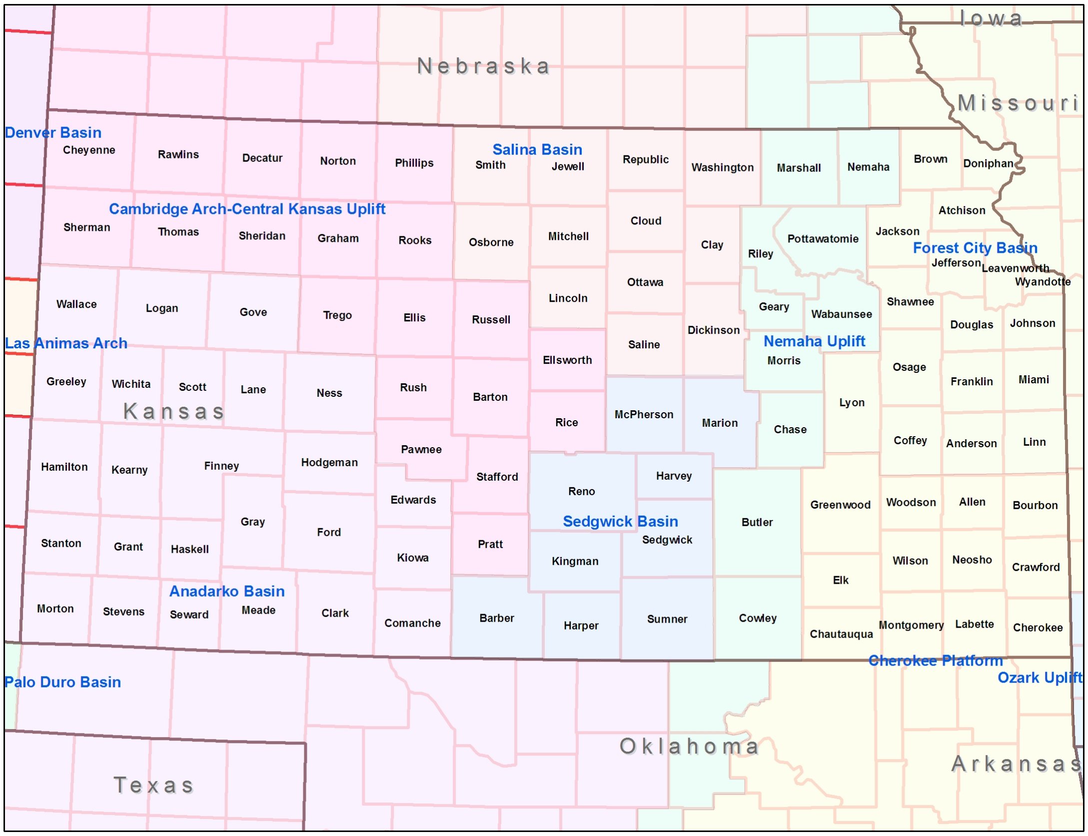


**Figure 3.** Map of Kansas showing exact alignment between county boundaries and the boundaries of the basins in the state.

Spud counts for 2002 were estimated using the well completion date field provided in the Kansas oil and gas database. The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud event for 2002. 2002 spud events were spatially allocated to the basin level using ARC/GIS.

Specifically, the following database analysis steps were performed to obtain oil and gas statistics by basins and counties

1. A master database of oil and gas wells and county level production data was obtained from KGS.
2. As shown in Figure 3, Kansas county boundaries align exactly with USGS-defined basin boundaries. The county-basin cross reference was created by using the spatial join tool in ARC/GIS. The cross reference was used to obtain basin-level statistics from county-level data.
3. <u>Basin-level production and well counts</u> – County level production data was obtained for calendar year 2002 from KGS. Basin level production was obtained by summing corresponding county-level production for all counties located within the boundaries of each basin in Kansas. Wells producing in 2002 were estimated by adding wells with valid completion dates (those without missing entries) and no plugging dates, or plugging dates after January 2002; and those wells without a workover code identified by nonzero last four characters of the API number; and those wells without a status code of "EOR," "SWD," or "WATER". Those wells completed more than 25

years before 2002 (in 1977 or earlier) were assumed to have been already beyond their active life spans and therefore were excluded from the active well count.

4. County-level production and well counts – County level production and well counts were directly available from the resulting dataset created in Step #3.
5. Spud-counts – Spud counts for 2002 were estimated using the well completion date field provided in the Kansas oil and gas database. The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud events for 2002. 2002 spud events were spatially allocated to the basin level using ARC/GIS.

**Nebraska**

The master cumulative oil and gas well database containing owner, county, location (latitude and longitude), well type, well status, spud date, and completion date information; and a lease-level historical production database were obtained from the Nebraska Oil and Gas Conservation Commission (NOGCC) in two separate data sets. The data were obtained in MS ACCESS format from the commission allowing for detailed analysis and queries to be conducted. These two databases were linked together by lease identification number, and therefore could be queried to obtain active producing wells in 2002. These 2002 wells (and leases) were then plotted and spatially assigned to a basin using GIS analysis. The oil and gas production from the 2002 active leases were then added by basin and by owner/operator to obtain 2002 total basin-level owner/operator production statistics.

Spud counts for 2002 were estimated using the well completion dates provided in the Nebraska oil and gas database. The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud events for 2002. 2002 spud events were spatially allocated to the basin level using ARC/GIS.

Specifically, the following database analysis steps were performed to obtain oil and gas statistics by basins and counties:

1. A master cumulative oil and gas well database and a lease-level historical production database were obtained from the NOGCC
2. These two databases were linked together by lease identification number (<Lease_No>). Active producing wells in 2002 were extracted using the <Rpt_Date> field. The wells in leases that reported production between January 1st, 2002 and December 31st, 2002 were selected as producing wells for 2002.
3. Basin-level production and well counts – The extracted 2002 wells (and leases) were plotted and spatially assigned to a basin using the spatial join tool in ARC/GIS to obtain basin-level production and well count.
4. County-level production and well counts – The database obtained from the NOGCC had a county code assigned to each well record. The production and well count of 2002 producing wells were added at the county level from the extracted 2002 wells.
5. Spud counts – Spud counts for 2002 were estimated using the well completion dates provided in the NOGCC database. The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud events for 2002. 2002 spud events were spatially allocated to the basin and county level using ARC/GIS.

**Arkansas**

Arkansas oil and gas production and other well information were obtained from the Arkansas Oil and Gas Commission. Well data included well location (latitude and longitude), county, company name, well type and well status information. The other database obtained contained historical production data by PRUID, a well identifier. The wells database was linked with the production database using the well identification number (PRUID) so that producing wells in 2002 could be estimated. Many wells did not have location in latitude/longitude format but rather in Town/Section/Range (TSR) data format. The TRS2LL program was used to convert these TRS data into latitude/longitude format in batch file mode (http://www.geocities.com/jeremiahobrien/trs2ll.html).

The 2002 active wells were plotted and spatially joined with oil and gas basins using GIS analysis. Well production was aggregated by basin and operator/owner to obtain production total by basins and owner/operator.

Spud count for 2002 was estimated using the well completion date field provided in the Arkansas oil & gas database (AOGC). The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud events for 2002. However the spud count obtained using this methodology was unreasonably low as compared to the count reported by the EIA for the entire state. Given the limitations of the database, it was determined to use the state-level spud count provided by EIA. The spud event was spatially allocated at the county level using well-count as surrogate and then aggregated to obtain basin-level spud count.

Specifically, the following database analysis steps were performed to obtain oil and gas statistics by basins and counties:

1. Arkansas oil and gas production and other well information were obtained from the AOGC.
2. Well data included well location (latitude and longitude), county, company name, well type and well status information. A second database obtained from AOGC contained historical production data by PRUID, a well identifier. The wells database was linked with the production database using the well identification number (PRUID). The producing wells in 2002 were identified using the <RptDate> field. Wells that reported production between January 1st, 2002 and December 31st, 2002 were selected as producing wells for 2002.
3. Many wells did not have location in latitude/longitude format but rather in Town/Section/Range (TSR) data format. The TRS2LL program was used to convert these TRS data into latitude/longitude format in batch file mode.
4. <u>Basin-level production and well counts</u> – The 2002 active wells were plotted and spatially joined with oil and gas basins using the spatial join tool in ARC/GIS. Well production was aggregated by basin to obtain the production total and well count by basins.
5. <u>County-level production and well counts</u> – The database obtained from the AOGC had a county code assigned to each well record. The production and well count of 2002 wells were added at the county level from the extracted 2002 wells.
6. <u>Spud counts</u> – The spud count for 2002 was estimated using the well completion date field provided in the AOGC database. The well records having completion dates between January 1st, 2002 and December 31st, 2002 were selected as spud events for 2002. However, the spud count obtained using this methodology was unreasonably low as

compared to the count reported by the EIA for the entire state. Given the limitations of the AOGC database, it was determined that the state-level spud count provided by EIA would be used. The spud events were spatially allocated at the county level using well-count as a surrogate and then aggregated to obtain basin-level spud counts.

**Texas**

ENVIRON attempted to obtain detailed oil and gas production and well databases from the Texas Railroad Commission (RRC), but several attempts to obtain this data were unsuccessful. The cost to access the complete database library from the RRC was determined to be beyond the budget and resources of this project, and further it could not be determined whether these databases would maintain historic information which could be used to determine 2002-specific statistics. ENVIRON discussed this issue with the Texas Commission on Environmental Quality (TCEQ) staff, and determined that further attempts to obtain this data from the RRC would not be useful.

However, the TCEQ has in the past obtained some data from the RRC which were determined to be useful for this analysis. RRC provided to TCEQ a complete dataset of well locations for the month of June 2001, in GIS shape file format. TCEQ provided these shape files to ENVIRON for use in this analysis. GIS analysis was used to intersect the well location dataset with the USGS-defined basin boundaries to determine basin-level well counts, assuming that these would not have changed substantially from June 2001 to the 2002 calendar year. It should be noted that well counts were not identifiable by well type from this data.

A summary of 2002 annual oil and gas production by county was obtained from the RRC. The GIS analysis of basin and county boundaries indicated that not all county boundaries align exactly with basin boundaries, as shown in Figure 4. The Marathon Thrust Belt and Permian Basin boundaries divide several Texas counties into partial counties. The county-level production in these divided counties was assigned to each of these two basins based on the fraction of 2001 wells in these counties located in each of the basins, as determined from the GIS shape file of 2001 well locations. For any other basin in which there was alignment between county and basin boundaries, basin total production was determined by summing county-level production for all counties within each basin.
For purposes of estimating spud counts in Texas, it should be noted that well completion date information was missing in the Texas oil and gas dataset obtained from TCEQ. Spud counts by Rail Road District were obtained from RRC. The spud counts were mapped to counties using a district-county cross reference obtained from the RRC. These 2002 spud events were spatially allocated to the basin level using a county-basin cross reference.

Specifically, the following database analysis steps were performed to obtain oil & gas statistics by basins and counties:

1. A complete dataset of well locations for the month of June 2001, in GIS shape file format, was obtained from TCEQ.
2. A summary of 2002 annual oil and gas production by county was obtained from the RRC online database.
3. The Marathon Thrust Belt and Permian Basin boundaries divide several Texas counties into partial counties. The county-level production in these divided counties was assigned

to each of these two basins based on the fraction of 2001 wells in these counties located in each of the basins, as determined from the GIS shape file of 2001 well locations.

4. Basin-level production and well counts – Wells having a status code of "OW," "OG," or "GW" were considered as active producing wells (these codes refer to “oil well”, “oil and gas well” and “gas well” respectively). The basin total production was determined by summing county-level production for all counties within each basin. The active well count by basins was obtained using the spatial join tool in ARC/GIS.
5. County-level production and well counts – The dataset obtained from TCEQ had a county code assigned to each well record. The active well counts for each basin were obtained by adding wells with a status code of OW, OG, or GW. County-level production was obtained directly from the RRC online database.
6. Spud Counts – Spud counts by Rail Road District were obtained from the RRC. The spud counts were mapped to counties using a District-County cross reference obtained from the RRC. These 2002 spud events were spatially allocated to the basin level using a county-basin cross reference.

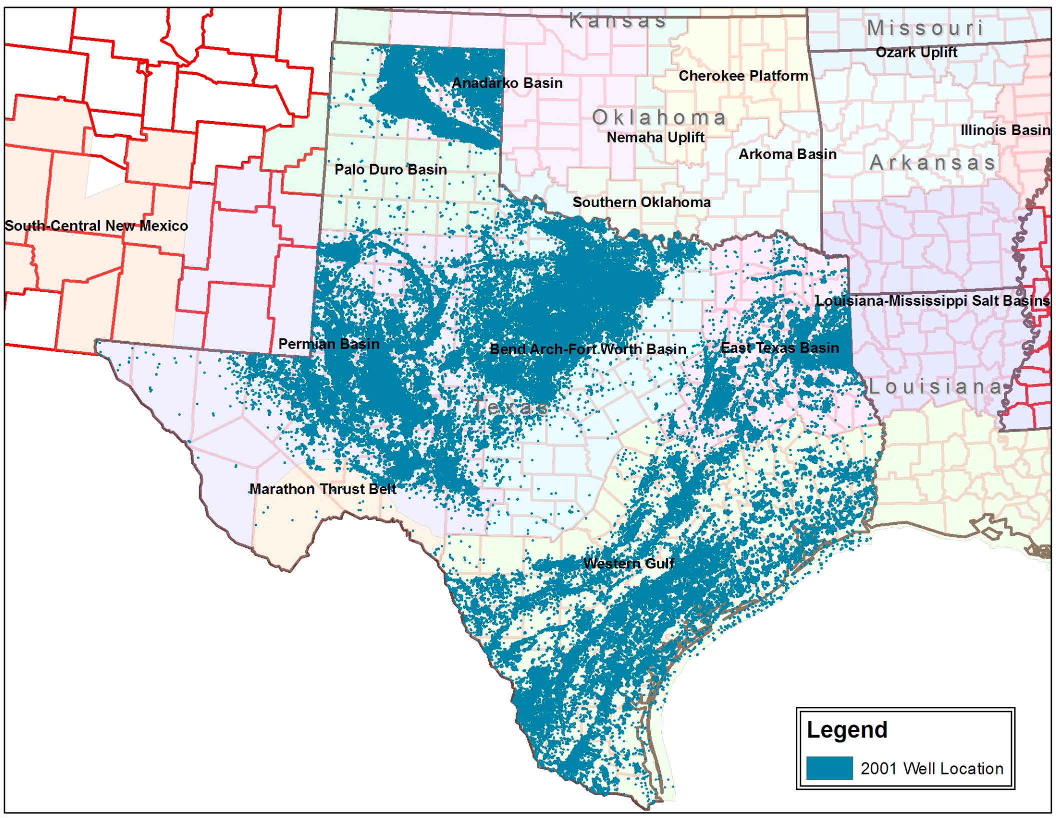


**Figure 4.** Map of Texas showing county boundaries and the boundaries of the basins in the state, and showing that the Marathon Thrust Belt and Permian Basin do not align exactly with county boundaries.

## Louisiana

Louisiana data were obtained from the Louisiana Department of Natural Resources (LADNR) with assistance from the Louisiana Department of Environmental Quality (LA DEQ). LADNR maintains a very detailed Oracle database of well locations, well type, well status, field-level production and field locations which was queried for 2002-specific data. From this query, the active well counts were determined by well location and spatially joined with the boundaries of

the Louisiana-Mississippi Salt Basins and the Western Gulf Basin using GIS analysis to determine basin-level well counts. Spud counts for each basin were determined by summing all wells that had a completion occurring between January 1 2002 and December 31 2002 and assigning these spuds to each basin using the well location.

Oil and gas production data were provided by field. The field locations data table was merged with the production by field using field ID, to determine the fraction of total Louisiana production occurring in each of the two basins.

Specifically, the following database analysis steps were performed to obtain oil & gas statistics by basins and counties:

1. The 2002 active wells dataset was obtained from LA DEQ. The 2002 production by field dataset was also obtained from LA DEQ.
2. The well database had duplicate well entries. Unique well records were selected from the well database.
3. The parish-basin cross reference was created using the spatial join tool in ARC/GIS. Separately, the field-parish cross reference table was obtained from LA DEQ, where field refers to active oil and gas well fields.
4. <u>Basin-level production and well counts</u> – The unique well records were linked with the parish-basin cross reference table to obtain the active well counts by basin. The field production was linked to the field-parish cross reference table on using the <Field_Id> data field to obtain parish level production. It should be noted that some oil and gas fields span more than one parish. Production from these fields was apportioned to each parish using a well count surrogate.
5. <u>County-level production and well counts</u> – County level production and well count was obtained directly from the dataset created in Step#3.
6. <u>Spud counts</u> – Spud counts for each basin and county were determined by summing all wells that had a completion occurring between January 1 2002 and December 31 2002 and assigning these spuds to each basin using the well location. The county level spud count was obtained by adding well completions occurring between January 1 2002 and December 31 2002 for each parish in the well database

**Condensate Production**

Condensate, for purposes of this analysis, is defined as liquid hydrocarbon production at gas wells. In practice, it is difficult to clearly distinguish between condensate and oil production since many state OGCC databases label all liquid hydrocarbon production as oil, and furthermore the distinction between oil and gas well designations is defined only by a gas-to-oil ratio (GOR) cutoff decided upon by each state OGCC. Except in very clear circumstances, in which a geographical region is dominated by gas production with only incidental oil production, it is difficult to distinguish between condensate and oil production.

Due to the organizational structures of the state OGCC databases that were used to develop the oil and gas statistics for this project, as described above, it was not always possible to link a production database to a well-level database, in which case it was impossible to determine if the "oil" production occurred at a true oil well, or at a gas well (in which case it should be termed condensate). For basins that span multiple states, including states where well-level production could not be determined, it was therefore not possible to determine the sum of condensate

production for the entire basin. Because of this lack of geographic consistency due to the limitations of the OGCC databases, this work does not present estimates of condensate production, but rather only total oil production for each basin.

However, because condensate tanks can be an important VOC source category, the recommendations section does present information on determining condensate tank emissions per unit of condensate production. If CENRAP or individual states are able to obtain more detailed well-level production data, such as potentially from use of a commercial database, these emissions factors could be used to determine condensate tank emissions.

In the case of Texas basins, it should be noted that the Texas Railroad Commission does track condensate production separately from oil production. The condensate production for all basins in Texas is shown in Table 2.

**Table 2**. 2002 by-basin condensate production for the State of Texas.

| **Basin** | **Condensate Production [bbl]** |
|---|---|
| Anadarko Basin (*portion in Texas*) | 939,154 |
| Bend Arch-Ft. Worth Basin (*portion in Texas*) | 1,310,103 |
| East Texas Basin | 3,875,885 |
| Marathon Thrust Belt | 320,014 |
| Palo Duro Basin (*portion in Texas*) | 39,148 |
| Permian Basin | 2,563,403 |
| Western Gulf Basin (*portion in Texas*) | 30,527,660 |
| **Texas Total** | 39,575,367 |

Note that the Anadarko, Bend Arch-Ft.Worth, Palo Duro and Western Gulf Basins' boundaries include sections of the basins outside of Texas. Condensate production for only the Texas portions of these basins is presented here. It should also be noted that the oil production totals for Texas, obtained from the RRC, are for true oil only since the RRC has already separately totaled the condensate production.

## Coal-Bed Methane Wells

Coal-bed methane (CBM) wells are gas wells in which the gas reservoir is trapped in underground flooded coal seams. These wells are typically shallow wells with well depths ranging from 3,000 – 5,000 feet, and require dewatering before any production can begin. Once production does begin the produced CBM well gas is characterized by high methane content, and an extremely low (or negligible) VOC content. This low VOC content affects estimates of VOC emissions from venting or fugitive sources such as blowdowns, dehydrators, or pneumatic devices. In analysis of some Rocky Mountain States basins, ENVIRON has made efforts to track CBM well counts and production separately from conventional wells to properly account for VOC emissions from these wells. However, due to the limitations in the CENRAP states' OGCC databases used for this analysis, well type was not identifiable from much of the oil and gas statistical data.

From the Arkansas and Kansas databases, it was possible to determine a count of CBM wells, although in the case of Kansas well-level production cannot be determined. In Arkanas, of the 3,776 active wells in the state, only 19 CBM wells were identified representing 0.5% of the active well count, a negligible proportion. In Kansas 804 individual CBM wells were identified, but these CBM wells represent only 1.7% of the active wells identified in the state for 2002. From the Texas RRC and Nebraska OGCC databases, no CBM wells were identified in either state. In Oklahoma the OCC database for gas wells identified no CBM wells. For Louisiana, the LADNR database does not identify a well type classification except by production values. Therefore Louisiana wells were classified only as oil or gas wells.

Due to these limitations, CBM wells and CBM gas production are not considered further in this analysis.

### Summary Statistics

The summary by basin of all of the individual state oil and gas statistics analyses is presented in Table 3, including gas production, oil production, condensate production, active well count, and spud count for each basin. These data are also presented in Appendix A, which references a MS Excel spreadsheet included as an attachment with this report that provides all detailed oil and gas production statistics derived as part of this task.

**Table 3**. 2002 gas production, oil production, active well counts and spud counts for all producing basins in the CENRAP domain.

| Basin | Gas Production [MCF] | Oil Production [bbl] | Active Well Count | Spud Count |
|---|---|---|---|---|
| Anadarko Basin | 1,732,269,135 | 40,279,230 | 88,406 | 2,327 |
| Arkoma Basin | 364,833,847 | 3,019,091 | 12,401 | 739 |
| Bend Arch-Ft. Worth Basin | 321,056,553 | 24,156,879 | 106,173 | 1,662 |
| Cambridge Arch-Central Kansas Uplift | 6,442,698 | 14,649,639 | 10,366 | 387 |
| Cherokee Platform | 31,040,321 | 16,693,567 | 33,779 | 862 |
| Denver Basin | 1,192,111 | 1,321,300 | 1,288 | 11 |
| East Texas Basin | 980,666,377 | 23,944,407 | 33,453 | 1,159 |
| Forest City Basin | 415,029 | 946,580 | 5,850 | 131 |
| Louisiana-Mississippi Salt Basins | 391,332,732 | 13,146,248 | 34,805 | 203 |
| Marathon Thrust Belt | 63,294,963 | 56,723 | 278 | 15 |
| Nemaha Uplift | 27,773,241 | 8,419,664 | 11,913 | 249 |
| Ozark Uplift | 48,946 | 0 | 5 | 0 |
| Palo Duro Basin | 31,360,922 | 6,215,265 | 2,556 | 48 |
| Permian Basin | 679,260,325 | 256,544,364 | 113,598 | 2,957 |
| Salina Basin | 0 | 227,996 | 247 | 3 |
| Sedgwick Basin | 24,983,651 | 3,196,023 | 3,455 | 137 |
| Southern Oklahoma Basin | 60,355,759 | 18,586,235 | 24,651 | 349 |
| Western Gulf Basin | 3,410,532,407 | 100,096,887 | 108,403 | 2,641 |
| **TOTAL** | **8,126,859,017** | **531,500,098** | **591,627** | **13,880** |

In addition, the data were summarized by basin for each state individually, for the use of each state's department of environmental quality. Table 4 shows the sum of gas production, oil production, active well counts and spud counts for all basins in each state, for all 6 states for which there is significant oil and gas production in the CENRAP domain.

**Table 4**. 2002 gas production, oil production, active well counts and spud counts for each basin in the CENRAP domain organized by state including state totals.

| State | Basin | Gas Production [MCF] | Oil Production [bbl] | Active Well Count | Spud Count |
|---|---|---|---|---|---|
| Arkansas | Arkoma Basin | 86,578,335 | 1,690 | 2,270 | 97 |
| | Louisiana-Mississippi Salt Basins | 13,895,085 | 4,699,223 | 1,438 | 63 |
| | Ozark Uplift | 48,946 | 0 | 5 | 0 |
| | **Arkansas Total** | **100,522,366** | **4,700,913** | **3,713** | **160** |
| Kansas | Anadarko Basin | 420,610,798 | 11,902,176 | 11,838 | 665 |
| | Cambridge Arch-Central Kansas Uplift | 6,442,210 | 13,349,217 | 9,383 | 371 |
| | Cherokee Platform | 6,187,659 | 1,826,639 | 12,942 | 386 |
| | Forest City Basin | 415,029 | 929,653 | 5,802 | 131 |
| | Nemaha Uplift | 438,666 | 1,958,147 | 2,603 | 61 |
| | Salina Basin | 0 | 216,420 | 237 | 3 |
| | Sedgwick Basin | 24,983,651 | 3,196,023 | 3,455 | 137 |
| | **Kansas Total** | **459,078,013** | **33,378,275** | **46,260** | **1,754** |
| Louisiana | Louisiana-Mississippi Salt Basins | 377,437,647 | 8,447,025 | 33,367 | 140 |
| | Western Gulf Basin | 972,402,468 | 51,658,179 | 15,533 | 224 |
| | **Louisiana Total** | **1,349,840,115** | **60,105,204** | **48900** | **364** |
| Nebraska | Cambridge Arch-Central Kansas Uplift | 488 | 1,300,422 | 983 | 16 |
| | Denver Basin | 1,192,111 | 1,321,300 | 1,288 | 11 |
| | Forest City Basin | 0 | 16,927 | 48 | 0 |
| | Salina Basin | 0 | 11,576 | 21 | 0 |
| | **Nebraska Total** | **1,192,599** | **2,650,225** | **2,340** | **27** |
| Oklahoma | Anadarko Basin | 980,495,277 | 22,751,853 | 50,037 | 1,327 |
| | Arkoma Basin | 278,255,512 | 3,017,401 | 10,131 | 642 |
| | Bend Arch-Ft. Worth Basin | 0 | 220,116 | 279 | 5 |
| | Cherokee Platform | 24,852,662 | 14,866,928 | 20,837 | 476 |
| | Nemaha Uplift | 27,334,575 | 6,461,517 | 9,310 | 188 |
| | Palo Duro Basin | 2,769,295 | 126,406 | 303 | 6 |
| | Southern Oklahoma Basin | 60,355,759 | 18,586,235 | 24,650 | 349 |
| | **Oklahoma Total** | **1,374,063,080** | **66,030,456** | **115,547** | **2,993** |
| Texas | Anadarko Basin | 331,163,060 | 5,625,201 | 26,531 | 335 |
| | Bend Arch-Ft. Worth Basin | 321,056,553 | 23,936,763 | 105,894 | 1,657 |
| | East Texas Basin | 980,666,377 | 23,944,407 | 33,453 | 1,159 |
| | Marathon Thrust Belt | 63,294,963 | 56,723 | 278 | 15 |
| | Palo Duro Basin | 28,591,627 | 6,088,859 | 2,253 | 42 |
| | Permian Basin | 679,260,325 | 256,544,364 | 113,598 | 2,957 |
| | Western Gulf Basin | 2,438,129,939 | 48,438,708 | 92,870 | 2,417 |
| | **Texas Total** | **4,842,162,844** | **364,635,025** | **374,877** | **8,582** |
| **GRAND TOTAL** | | **8,126,859,017** | **531,500,098** | **591,637** | **13,880** |

From these summary statistics, the following eleven basins were identified as the "major" oil and gas production basins in the CENRAP region because they collectively represent greater than 95% of production of oil, production of gas, and active well counts:

- Anadarko Basin
- Arkoma Basin
- Bend Arch-Fort Worth Basin
- Cambridge Arch-Central Kansas Uplift
- Cherokee Platform
- East Texas Basin
- Louisiana-Mississippi Salt Basins
- Nemaha Uplift
- Permian Basin
- Southern Oklahoma Basin
- Western Gulf Basin

Recommendations for emissions calculations and specific input data for those calculations are provided for these specific basins, based on this analysis, in the sections below.

## TASK 2a: LITERATURE REVIEW

A literature review was conducted to obtain information from published studies or reports on activity, equipment, configuration, emissions, and usage of typical oil and gas area sources to improve the input data used to generate emissions inventories for the CENRAP states. This task consisted of obtaining inventory input data from one of the two sources considered in this work – the other source is the survey process described in the following section – and was modeled after the specific literature review request by CENRAP.

CENRAP identified the need to improve input information used to generate state-level and CENRAP regional inventories of oil and gas area sources and this represents the bulk of the work product of this project. This information includes such data as:

- engine types
- engine counts
- horsepower
- annual usage
- emissions factors
- configuration
- natural gas compositions
- venting statistics
- fugitive components
- pneumatic device counts
- pneumatic device and fugitive component bleed rates
- dehydrator configurations
- heater usage

This list is not intended as a complete list, but only a sample of the type of data used in calculations of various source categories related to oil and gas. The complete description of the methodology and input data recommended for each major oil and gas source category considered in this work is found in the recommendations section of the report, along with a list of the specific major source categories for which literature data was sought.

Two sources were used to select specific literature to include in this task: (1) a list compiled by CENRAP and specifically cited in the workplan for this project; and (2) additional studies of which ENVIRON is aware that could provide useful input to oil and gas inventory calculations. The detailed list of literature considered in this work is presented below in Table 5:

**Table 5.** List of studies and other literature reviewed as part of Task 1.

| Study Number | Title | Geographic Domain |
|---|---|---|
| 1 | WRAP Phase III Oil and Gas Emissions Inventory (Bar-Ilan, et al., 2008) | Western regional U.S. |
| 2 | WRAP Phase II Oil and Gas Emissions Inventory (Bar-Ilan et al., 2007) | Western regional U.S. |
| 3 | WRAP Phase I Oil and Gas Emissions Inventory (Russell, et al., 2005) | Western regional U.S. |
| 4 | MMS Analysis to Quantify Oil and Gas Activity in the Gulf of Mexico Region (Wilson, et al., 2007) | Gulf of Mexico offshore oil and gas wells |
| 5 | Ozone Precursors Emission Inventory for San Juan and Rio Arriba Counties, New Mexico (Russell, et al., 2006) | San Juan and Rio Arriba Counties in the Four Corners region of New Mexico |
| 6 | NETAC Tyler/Longview/Marshall Flexible Attainment Region Emission Inventory for Ozone Precursors (Pollution Solutions, 2005) | Boundaries of the Tyler/Longview/Marshall attainment region in Northeast Texas |
| 7 | "*VOC Emissions from Oil and Condensate Tanks*" Study performed for HARC by URS (Hendler et al., 2006) | Generally applicable to oil and gas development in Texas |
| 8 | Oil and Gas Area Source Emissions Estimates provided by TCEQ (Pendleton, et al., 2008) | State of Texas |
| 9 | Inventory of Nitrogen Oxide Emissions in Alberta's Upstream Oil and Gas Industry (Bhardwaj, 2002) | Province of Alberta, Canada |
| 10 | DIAL Measurements of Fugitive Emissions from Natural Gas Plants and Comparison with Emissions Factors (Chambers, et al., 2006) | Province of Alberta, Canada |
| 11 | NETAC Tyler/Longview/marshall flexible Attainment Region Special Study Relating to Oil and Gas Production: 2005 and 2007 Emissions from Compressor Engines with Consideration for Load Factor (Pollution Solutions, 2007) | Boundaries of the Tyler/Longview/Marshall attainment region in Northeast Texas |

In all cases, literature was reviewed for useful information and to determine the applicability of that information to oil and gas inventory calculations in the CENRAP domain. Specifically, ENVIRON used the following criteria to analyze the literature and determine its applicability to the recommended data:

4. Geographic scope: The most important criterion applied to determine the applicability of a literature source was the geographic scope which the study or report covers. Production characteristics vary on the basin level, with some basins being dominated by oil or gas production, or having significant CBM gas production where other basins do not, or incorporating oil shale activities where other basins do not. Drilling operations vary significantly from region to region, driven primarily by the type and depth of well drilled and the associated rig horsepower requirements. Composition of the produced gas and oil vary widely from basin to basin, with respect to the condensate content of gas, VOC content of gas, oil composition, and presence of sulfur. These are some of the regional differences that can affect the usage of particular equipment and would necessarily affect the development of oil and gas emissions inventories for a particular basin. ENVIRON's experience in the development of oil and gas emissions inventories leads us to conclude that regional differences in oil and gas production activities are sufficient that local data must be used where possible.
5. Age of study: There has been increased interest in emissions from oil and gas exploration and production activities in the past decade, driven by the substantial growth in this activity particularly in the Rocky Mountain States. Because of this, new studies have been conducted which may result in older studies becoming out of date. To the extent possible this criterion was applied to the selection of specific data from some of the studies and reports listed in Table 5. Where a more recent study investigating a particular subject was available, the more recent study was used.
6. Consistency of data with other sources: Data consistency was used as a QA/QC tool to evaluate the usefulness and applicability of data extracted from all of these studies and reports. Data were reviewed to be consistent both with other studies, and with detailed information collected by ENVIRON as part of the development of oil and gas inventories in the western states. This consistency was evaluated for sources where it is expected that the configuration, emissions and usage would be similar from region to region, such as for a particular make and model of engine.

These criteria were applied to the sources listed in Table 5 and data that were determined to be useful were extracted and compiled in a master matrix of data fields for estimation of emissions from all the major oil and gas source categories. This information was supplemented by data obtained from a limited survey of select oil and gas companies, which is described further in the survey section below. From the combined literature review and survey data recommended data were determined for specific data fields.

## TASK 2b: LIMITED INDUSTRY SURVEY

In addition to the literature review described above in Task 2a, ENVIRON also undertook a limited survey targeted at major oil and gas companies operating in the CENRAP region to obtain additional data from these companies for use as input data to emissions inventory calculations for oil and gas area sources. This was done primarily for two reasons. First, through the development of the Rocky Mountain States oil and gas emissions inventories under the various WRAP projects it has been ENVIRON's experience that industry participation is essential to develop the most accurate database of information on equipment, usage of the equipment, field processes, and emissions factors and other support data. This is because oil and gas field operations vary greatly from basin to basin and only these companies can provide accurate information about the equipment they own and its usage. Second, through the WRAP

regional inventories in the western U.S., ENVIRON has developed working relationships and contacts with many of the major oil and gas companies operating in this region, and therefore it was supposed that ENVIRON's use of those contacts could result in a good response to a survey. In the past decade, the oil and gas industry has seen considerable consolidation, so that a large fraction of oil and gas production in most of the continental U.S. is now owned by a smaller number of companies. As a result of this consolidation, many of the same companies with which ENVIRON has developed contacts particularly through the ongoing IPAMS/WRAP Phase III project (Bar-Ilan, et al., 2008) are those with a large ownership of production in the CENRAP domain.

Companies that were targeted for the survey process were identified by analysis of the oil and gas production statistics developed as part of Task 1. To the extent possible, a list of the top ownership of gas production, oil production and well counts was developed for each basin. However, for Texas, Louisiana, and Kansas the production and well statistics were unavailable by owner/operator, and it was not possible to generate a ranked list of ownership by basin. For these states, the respective OGCC's did provide a list of top ownership of oil and gas production for the state as a whole and this was assumed to apply to all basins in these states. For Oklahoma, well-level oil production data were not available, and a similar methodology to that in Texas, Louisiana and Kansas was applied to determine top oil producing companies in Oklahoma. These lists were then reviewed to determine which companies had significant past interaction with ENVIRON through the WRAP Phase I, Phase II, Phase III western regional oil and gas projects and the NMED ozone precursors project in the Four Corners region. These were the primary projects in which ENVIRON interacted with industry participants in survey processes. The top companies list was then evaluated in order to condense the list to only those companies that ENVIRON determined from past experience would be likely to participate in a survey process. Since the industry has consolidated, those companies operating in the same basin are likely to use similar processes and equipment configurations, therefore the goal of condensing the list to a select number of companies was to ensure that each basin was represented by at least one company that ENVIRON determined might be likely to respond to the survey.

The final condensed list of companies that were selected for consideration in this survey process is presented in Table 6, which indicates the geographic areas of major operations owned by each company. Of the companies listed in Table 6, ExxonMobil, Occidental Petroleum, El Paso Corporation, and Petro-Chem Operating were not included in the survey process because of ENVIRON's past experience in developing a survey process for the WRAP and separately for the NMED. These companies were ones that were resistant to participation in the past survey efforts and thus deemed unlikely to agree to participate in this CENRAP survey process. These companies were not sent a survey form.

The remaining nine companies were sent a survey form, but of these companies only four responded with a sufficiently complete survey response to be usable. It should be noted that ENVIRON has worked extensively with BP America in several oil and gas related projects and has very good contacts with this company. BP America is notable among the oil and gas companies with which ENVIRON has worked for the extensive and detailed emissions inventory recordkeeping documents that the company produces, and has made available to ENVIRON as part of the western regional work. It was hoped that BP would also be willing to participate in this CENRAP survey process, but to date no survey response has been received from the company. If a survey response is received by ENVIRON from BP America beyond the end date of this project, ENVIRON will make the survey responses available to CENRAP as these will

likely be useful additional data covering the regions where BP America has major oil and gas operations.

**Table 6.** Summary of companies contacted as part of the survey process including their regions of operation and the status of their responses to the survey.

| Company | Geographic Area of Major Operations (by basin) | Survey Sent (Y/N) | Survey Received (Y/N) |
|---|---|---|---|
| BP America | Anadarko, Arkoma, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, East Texas, Marathon Thrust Belt, Palo Duro, Permian, Sedgwick, Western Gulf | Y | N |
| Conoco-Phillips | Anadarko, Bend Arch-Ft. Worth, East Texas, Marathon Thrust Belt, Nemaha Uplift, Palo Duro, Permian, Sedgwick, Western Gulf | Y | N |
| Chevron | Southern Oklahoma | Y | N |
| Anadarko Petroleum | Anadarko, Arkoma, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, East Texas, Permian, Southern Oklahoma, Western Gulf | Y | Y |
| Encana USA | Bend Arch-Ft. Worth, East Texas, Permian, Western Gulf | Y | Y |
| Devon Energy | Anadarko, Arkoma, Bend Arch-Ft. Worth, East Texas, Louisiana-Mississippi Salt, Nemaha Uplift, Permian, Sedgwick, Western Gulf | Y | Y |
| Noble Energy | Anadarko, Arkoma, Cambridge Arch-Central Kansas Uplift, Cherokee Platform, East Texas, Louisiana-Mississippi Salt Basins, Nemaha Uplift, Permian, Southern Oklahoma, Western Gulf | Y | Y |
| EOG Resources | Anadarko, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, East Texas, Nemaha, Permian, Southern Oklahoma, Sedgwick | Y | N |
| XTO | Anadarko, Arkoma, Bend Arch-Ft. Worth, Cambridge Arch-Central Kansas Uplift, Cherokee Platform, East Texas, Nemaha Uplift, Palo Duro, Permian, Southern Oklahoma, Western Gulf | Y | N |
| ExxonMobil | Arkoma, Louisiana-Mississippi Salt Basins | N | – |
| Occidental Petroleum | Permian | N | – |
| El Paso Corporation | Louisiana-Mississippi Salt Basins | N | – |
| Petro-Chem Operating | Louisiana-Mississippi Salt Basins | N | – |

The four companies that did provide survey responses – Andarko Petroleum, Devon Energy, Encana USA, and Noble Energy – cover a wide geographic range of activities in the CENRAP domain including many of the major basins of interest for this study. The data provided in these surveys were evaluated for quality, applicability and usefulness and combined with literature

review data for particular fields to generate a combined data matrix as described below in the recommendations section of the report. The survey data from the four responding companies were evaluated using the same general criteria that were used to evaluate literature review sources. The specific criteria used to evaluate the surveys were:

1. Geographic specificity: Survey responses were evaluated to determine if the data provided were sufficiently specific to individual basins where the respondent had significant operations. Broad, company-wide data and assumptions were generally not included in the summary data matrix because these data could not then be applied to specific geographic regions.
2. Quality of data: ENVIRON reviewed survey responses for data quality to determine if responses to specific survey data requests were beyond the typical range of these responses as determined by comparison to similar data collected by ENVIRON as part of other oil and gas survey efforts. In these cases, efforts were made to clarify responses by contacting individual companies and by reviewing their operations for any unusual activities that would warrant extremely high or low data for particular data fields. Data that were determined to be beyond the range of typical values for a particular data field were generally rejected from further consideration in this analysis.
3. Applicability and usefulness: Data were reviewed for applicability and usefulness in terms of the basin-level emissions estimates that are described in the recommendations section below. Responses to the survey that could not be easily converted into representative equipment or process input data were rejected from consideration in this analysis. An example of this is a response indicating the total number of wellhead compressors operated by the company in a basin or for the entire regional operations of the company. Without detailed active well count ownership by the company, it would be impossible to determine the fraction of wells with wellhead compressors, which is the necessary input data field for estimating basin-level wellhead compressor emissions.

The surveys requested information on the following major oil and gas source categories:

- Drilling rigs
- Compressor engines
- Artificial lift engines
- Heaters
- Condensate and Oil tanks
- Fugitive emissions
- Pneumatic devices
- Completion/recompletion venting and well blowdowns

These source categories were selected based on ENVIRON's past work and current IPAMS/WRAP Phase III analysis (Bar-Ilan, et al., 2008) as being the most significant contributors to NOx and VOC emissions sources from combustion and fugitive/venting source categories. In addition to these, surveys requested information on basin-level average natural gas composition analyses, which provide necessary input information on the VOC content of gas for estimating VOC emissions from fugitive and venting sources, and for $H_2S$ content of gas to separately track these emissions.

The survey forms asked for basic data that would be used to determine necessary input values for basin-level emissions calculations. These included data fields such as: equipment counts;

horsepower, load factors, firing rates, usage and emissions factors; equipment configuration for multi-engine equipment (e.g. drilling rigs); venting rates and event counts for venting source categories; well configurations for estimating emissions from pneumatics and fugitives; and basic emissions rate data for estimating flashing and working/breathing losses from stock tanks. The complete set of data requests for all source categories considered in the survey process are presented in the survey questionnaire form, which is provided as Appendix B.

## TASK 3a: RECOMMENDED SOURCE CATEGORY EMISSION CALCULATION METHODOLOGIES AND INPUT DATA FOR BASELINE 2002 EMISSIONS

This section describes the recommended methodologies and input data to be used in estimating basin-level emissions of each major oil and gas source category for all of the CENRAP basins for the 2002 baseline year. This section presents the detailed methodologies as an equation or series of equations, and defines the values of the terms of these equations for each major oil and gas basin identified as part of Task 1. Equations are presented for estimating emissions for a single source in a category, and then to scale that source category to basin-level emissions. The major oil and gas area source categories considered in this analysis, and whose emissions estimation methodologies and input data are presented below, are:

- Wellhead Compressor Engines
- Lateral Compressor Engines
- Artificial Lift Engines (Pumpjacks)
- Drilling Rigs
- Heaters
- Flaring
- Oil Tanks (Flashing and Working & Breathing Losses)
- Condensate Tanks (Flashing and Working & Breathing Losses)
- Dehydrators
- Completion Venting
- Well Blowdowns
- Fugitive Emissions
- Pneumatic Devices

While this does not represent a complete list of all oil and gas area source categories, this list comprises the major area source categories that contribute the vast majority of emissions to a basin-level inventory per ENVIRON's experience in development of these inventories. These are also the source categories with the most complete set of input data that can be obtained through literature review and survey efforts, and thus result in the least inaccuracy and error in emissions estimation.

Following the information collected as part of the literature review and limited survey efforts, described in Tasks 2a and 2b, ENVIRON gathered these data together on all of the major oil and gas area source categories and developed a master data matrix to determine the most suitable data for each source category emissions estimate. From the data matrix specific values were selected as input data for emissions estimates for each source category for each major basin, and a rationale is provided for the choice of input data. In general the selection of input data made use of information from the industry survey responses to the extent possible. The survey data was assessed as described above for geographic specificity, quality of data, and applicability and

if the data passed all of these criteria the survey data was recommended. This is because the operators of these sources are believed to have the most accurate information on equipment types, horsepower, usage, and emissions factors. If the surveys were unable to provide usable, high quality data for a particular input data field, the next choice was to recommend similar data from the literature review. As discussed above, the data obtained from literature review were also subject to specific criteria regarding geographic scope, age of the study and consistency of the data with other known or published data with which ENVIRON has worked. Where neither survey nor literature data were available for a particular data input for a particular basin, the average of that value across all other CENRAP basins was used. For each data field for each source category and for all of the major basins, a summary is provided of the rationale for selection of the data source.

It should be noted that these input data are intended for use in developing CENRAP's broad regional inventory and as such provide information necessary to estimate emissions on the basin level only. There are various studies, conducted by regional government agencies or state DEQs and other agencies and organizations that have focused on a specific aspect of oil and gas area source emissions for very specific regions. ENVIRON is aware that the TCEQ and other Texas agencies have sponsored studies that focus on inventorying equipment or emissions for very specific geographical regions, but we are not aware of similar studies in other CENRAP states. Due to the need to make broad, basin-level assumptions in order to tractably estimate emissions for the entire CENRAP domain, it is not always possible to incorporate data from localized studies. However, CENRAP should consider analyzing the results of any detailed study to determine if some synthesis is possible that would produce improved emissions estimates for the region covered by the study.

Finally, it should be noted that these data are intended as inputs to emissions inventory calculations at the basin level. The inventory calculations themselves are not a part of the scope of this work, but the data are presented in a form that would allow for conducting these calculations in the future. For this reason the data are also provided in the accompanying recommended data spreadsheet.

**Wellhead Compressor Engines**

Methodology:

Wellhead compressor engines represent one of the most significant oil and gas NOx area source categories. Depending on the basin and the fractional usage of these engines, there may be many thousands of individual wellhead compressor engines located at many well sites. These engines are used to boost produced gas pressure from downhole pressure to the required pressure for delivery to a transmission pipeline. Generally these engines are natural-gas powered, using the produced gas (after some separation and dehydration) as fuel for a spark-ignited internal combustion engine. Based on numerous survey responses as part of this analysis and previous ENVIRON experience, it has been determined that natural gas produced with a high sour gas content ($H_2S$) is used directly in wellhead compressor engines once they have been properly modified to handle $H_2S$. Therefore wellhead compressor engines are only a source of sulfur emissions if $H_2S$ is present in the gas. They generally operate 8760 hours per year with a minimum of down-time. Any down-time is typically associated with repairs or routine maintenance, but gas production companies attempt to minimize this down-time to the extent possible.

The most common makes of wellhead compressor engines are Caterpillar, Waukesha, and Ajax. Generally wellhead compressor engines are uncontrolled, but two distinct types are utilized: "rich-burn" engines that are characterized by NOx emissions factors in the range of approximately 10 – 20 g/bhp-hr; and "lean-burn" engines that are characterized by NOx emissions factors in the range of approximately 1.0 – 5.0 g/bhp-hr. The exact NOx emissions factors depend on the horsepower of the engine, the make and model, the model year of the engine, and whether the engine has been converted from a rich-burn to a lean-burn engine. Wellhead compressor engines are distinct from lateral or central compressor engines in that they are smaller in size. Generally wellhead compressor engines have a horsepower range of approximately 50 – 250 hp. The actual brake horsepower of the wellhead compressor engine in use in the field depends primarily on the field gas pressure. Larger engines installed at a time when field pressure was high may be running at very low load factors if the well is in significant decline in production.

Again it should be noted that the information presented below is intended to generate basin-level emissions estimates for wellhead compressor engines. There have been very detailed studies that have attempted to inventory these engines for specific gas fields or other localized geographic regions, but these studies often cannot present the data in a manner that allows for a basin-level calculation. The methodology and recommended data are for a basin-level calculation that necessitates relying on assumptions of wellhead compressor engine composition to make the calculation tractable. However, CENRAP should continue to consider additional studies that inventory these engines in specific geographic regions and incorporate them into a basin-level analysis.

The basic methodology for estimating emissions from wellhead compressor engines is shown in Equation (1):

Equation (1) $$E_{engine} = \frac{EF_i \times HP \times LF \times t_{annual}}{907{,}185}$$

where:

$E_{engine}$ are emissions from a rich-burn or lean-burn compressor engine [ton/year/engine]
$EF_i$ is the emissions factor of pollutant $i$ [g/hp-hr] (note that this may be different for NOx emissions from rich-burn vs. lean-burn engines)
$HP$ is the horsepower of the engine [hp]
$LF$ is the load factor of the engine
$t_{annual}$ is the annual number of hours the engine is used [hr/yr]

Extrapolation to Basin-Wide Emissions

Each basin is represented in this work by a single representative rich- and lean-burn wellhead compressor engine make/model. The emissions are then scaled to the basin level using the ratios of rich-burn engines to total engines, lean-burn engines to total engines, the fraction of wells with wellhead compressor engines, and the total well count in the basin, according to Equation (2):

Equation (2) $$E_{engine,TOTAL} = \left(C_{Rich} E_{engine,Rich} + C_{Lean} E_{engine,Lean}\right) \times W_{TOTAL} \times f_{wellhead}$$

where:

$E_{engine,TOTAL}$ is the total emissions from compressor engines in the basin [ton/yr]
$E_{engine,Rich}$ is the total emissions from a single representative rich-burn compressor engine per Equation (1) [ton/yr]
$E_{engine,Lean}$ is the total emissions from a single representative lean-burn compressor engine per Equation (1) [ton/yr]
$C_{Rich}$ is the fraction of wellhead compressors in the basin that are rich-burn
$C_{Lean}$ is the fraction of wellhead compressors in the basin that are lean-burn
$W_{TOTAL}$ is the total well count in the basin
$f_{\text{wellhead}}$ is the fraction of all wells in the basin with wellhead compressor engines

It is recommended to use well count as a surrogate for scaling wellhead compressor emissions to the basin level as gas production estimates may underestimate the number of wellhead compressors in use. County-level emissions estimates would then be derived by allocating basin total wellhead compressor engine emissions to the county level by the fraction of total basin wells in each county.

Input Data

The recommended input data are presented in Tables 7 and 8:

**Table 7**. Recommended engine operating parameters for use in estimating wellhead compressor emissions for all major CENRAP basins.

| | Typical Engine Operating Parameters | | | | | |
|---|---|---|---|---|---|---|
| **Basin** | **Fraction of wells with wellhead compressors** | **Rated Horsepower [hp]** | **Annual Activity [hrs]** | **Load Factor** | **Fraction Rich Burn** | **Fraction Lean Burn** |
| Anadarko Basin | 0.045 | 130 | 8760 | 0.75 | 0.872 | 0.128 |
| Arkoma Basin | 0.025 | 73 | 8760 | 0.93 | 1.000 | 0.000 |
| Cambridge Arch-Central Kansas Uplift | 0.003 | 48 | 8760 | 1.00 | 1.000 | 0.000 |
| Cherokee Platform Basin | 0.029 | 101 | 8760 | 0.85 | 0.910 | 0.090 |
| East Texas Basin | 0.015 | 242 | 8760 | 0.66 | 0.970 | 0.030 |
| Fort Worth Basin | 0.100 | 124 | 8760 | 0.85 | 0.862 | 0.138 |
| Louisiana-Mississippi Salt Basins | 0.073 | 46 | 8760 | 0.85 | 0.872 | 0.128 |
| Nemaha Uplift | 0.019 | 36 | 8760 | 0.88 | 1.000 | 0.000 |
| Permian Basin | 0.025 | 73 | 8760 | 0.85 | 0.700 | 0.300 |
| Southern Oklahoma Basin | 0.020 | 30 | 8760 | 0.90 | 1.000 | 0.000 |
| Western Gulf Basin | 0.450 | 207 | 8760 | 0.80 | 0.825 | 0.175 |

**Table 8**. Recommended rich-burn and lean-burn engine emissions factors for use in estimating wellhead compressor emissions for all major CENRAP basins.

| Basin | Rich-Burn Engine Emissions Factors [g/bhp-hr] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | NOx | CO | VOC | $PM_{10}$ | $H_2S$ | SOx | $CO_2$ | $CH_4$ |
| Anadarko Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Arkoma Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Cambridge Arch-Central Kansas Uplift | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Cherokee Platform Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| East Texas Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 3.69 | 110 | 0.23 |
| Fort Worth Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Louisiana-Mississippi Salt Basins | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Nemaha Uplift | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Permian Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 14.19 | 110 | 0.23 |
| Southern Oklahoma Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Western Gulf Basin | 14.28 | 4.63 | 0.84 | 0.0095 | N/A | 0 | 110 | 0.23 |
| **Basin** | **Lean-Burn Engine Emissions Factors [g/bhp-hr]** | | | | | | | |
| | **NOx** | **CO** | **VOC** | **$PM_{10}$** | **$H_2S$** | **SOx** | **$CO_2$** | **$CH_4$** |
| Anadarko Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Arkoma Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Cambridge Arch-Central Kansas Uplift | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Cherokee Platform Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| East Texas Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 3.69 | 110 | 1.45 |
| Fort Worth Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Louisiana-Mississippi Salt Basins | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Nemaha Uplift | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Permian Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 14.19 | 110 | 1.45 |
| Southern Oklahoma Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |
| Western Gulf Basin | 3.10 | 2.29 | 1.51 | 0.038 | N/A | 0 | 110 | 1.45 |

<u>Data Sources</u>

Engine operating parameters were derived from survey data for most basins. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. For the East Texas Basin, the recent study by NETAC (Pollution Solutions, 2007) on load factors for wellhead compressor engines was used as a source for the load factors.

Most engine emissions factors were obtained from the NMED ozone precursors study in Northwest New Mexico (Russell, et al., 2006), which contained an extensive database of emissions factors for a range of wellhead compressor engine makes/models. From this database average rich-burn and lean-burn engine emissions factors were derived. $PM_{10}$, $CO_2$, and $CH_4$ emissions factors were obtained from AP-42 (EPA, 2000).

$SO_2$ emissions from wellhead compressor engines occur only if there is a significant sulfur concentration in the fuel as $H_2S$ (sour gas). In the case that there is a significant $H_2S$ concentration, the wellhead compressors are specially fitted with stainless steel components ("trimmed") to allow the compressor to run this fuel. Therefore it is assumed that all $H_2S$ in the fuel is combusted and emitted as $SO_2$. The $SO_2$ emissions factors presented in Table 8 are calculated from the $H_2S$ concentration using the brake-specific fuel consumption (BSFC) of a natural-gas fired, spark-ignited engine of the appropriate horsepower obtained from the EPA's NONROAD model (EPA, 2005a).

**Lateral Compressor Engines**

Methodology:

Lateral compressor engines are mid-sized compressor engines used to gather gas from a large number of individual well sites. Although these engines are generally significantly larger than wellhead compressor engines, the lateral compressor stations are generally smaller than central compressor stations and often do not trigger Title V or other permitting requirements. Whereas wellhead compressor engines may be used quite extensively – and in certain basins most gas wells will have a wellhead compressor engine – lateral compressor engines generally serve groups of 20 – 100 individual wells. Lateral compressors are generally in the range of 1000 – 1500 hp, and may also have rich-burn and lean-burn models. Unlike wellhead compressors, more lateral compressors are likely to be lean-burn engines.

Emissions from lateral compressors are estimated using a similar methodology to that of wellhead compressors. The basic methodology for estimating emissions from later compressor engines is shown in Equation (3):

Equation (3) $$E_{engine} = \frac{EF_i \times HP \times LF \times t_{annual}}{907{,}185}$$

where:

$E_{engine}$ are emissions from a rich-burn or lean-burn compressor engine [ton/year/engine]
$EF_i$ is the emissions factor of pollutant $i$ [g/hp-hr] (note that this may be different for NOx emissions from rich-burn vs. lean-burn engines)
$HP$ is the horsepower of the engine [hp]
$LF$ is the load factor of the engine
$t_{annual}$ is the annual number of hours the engine is used [hr/yr]

Extrapolation to Basin-Wide Emissions

Basins are considered to be composed of a single representative rich- and lean-burn lateral compressor engine make/model. The emissions are then scaled to the basin level using the ratios of rich-burn engines to total engines, lean-burn engines to total engines, the fraction of wells with lateral compressor engines, and the total well count in the basin, according to Equation (4):

Equation (4) $$E_{engine,TOTAL} = \left(C_{Rich}E_{engine,Rich} + C_{Lean}E_{engine,Lean}\right) \times W_{TOTAL} \times f_{lateral} \times \left( 1/N_{lateral} \right)$$

where:

$E_{engine,TOTAL}$ is the total emissions from lateral compressor engines in the basin [ton/yr]
$E_{engine,Rich}$ is the total emissions from a single representative rich-burn compressor engine per Equation (1) [ton/yr]
$E_{engine,Lean}$ is the total emissions from a single representative lean-burn compressor engine per Equation (1) [ton/yr]
$C_{Rich}$ is the fraction of lateral compressors in the basin that are rich-burn
$C_{Lean}$ is the fraction of lateral compressors in the basin that are lean-burn
$W_{TOTAL}$ is the total well count in the basin
$f_{\mathrm{lateral}}$ is the fraction of all wells in the basin that are served by lateral compressor engines
$N_{\mathrm{lateral}}$ is the number of wells served by a single lateral compressor engine

As with wellhead compressor engines, it is recommended that well count be used as a surrogate for scaling lateral compressor emissions to the basin level. County-level emissions estimates would then be derived by allocating basin total lateral compressor engine emissions to the county level by the fraction of total basin wells in each county. It should be noted that not in all basins are lateral compressors used, and this is dependent on a complex combination of factors that include field pressures, gas production in the basin, pipeline infrastructure, and the configuration of central compressor stations.

Input Data

The recommended input data are presented below in Tables 9 and 10:

**Table 9**. Recommended engine operating parameters for use in estimating lateral compressor engine emissions for all major CENRAP basins.

| | Typical Engine Operating Parameters | | | | | | |
|---|---|---|---|---|---|---|---|
| **Basin** | **Fraction of wells with lateral compressors** | **Number of wells per lateral compressor** | **Rated Horsepower [hp]** | **Annual Activity [hrs]** | **Load Factor** | **Fraction Rich Burn** | **Fraction Lean Burn** |
| Anadarko Basin | 0.015 | 20 | 1100 | 8760 | 0.74 | 0.44 | 0.56 |
| Arkoma Basin | 0 | N/A | N/A | N/A | N/A | N/A | N/A |
| Cambridge Arch-Central Kansas Uplift | 0 | N/A | N/A | N/A | N/A | N/A | N/A |
| Cherokee Platform Basin | 0 | N/A | N/A | N/A | N/A | N/A | N/A |
| East Texas Basin | 0.045 | 20 | 1128 | 8760 | 0.581 | 0.45 | 0.55 |
| Fort Worth Basin | 0.01 | 20 | 1340 | 8760 | 0.7405 | 0.5 | 0.5 |
| Louisiana-Mississippi Salt Basins | 0 | N/A | N/A | N/A | N/A | N/A | N/A |
| Nemaha Uplift | 0 | N/A | N/A | N/A | N/A | N/A | N/A |
| Permian Basin | 0.02 | 20 | 1340 | 8760 | 0.7405 | 0.38 | 0.63 |
| Southern Oklahoma Basin | 0 | N/A | N/A | N/A | N/A | N/A | N/A |
| Western Gulf Basin | 0.03 | 20 | 1340 | 8760 | 0.7405 | 0.25 | 0.75 |

**Table 10**. Recommended rich-burn and lean-burn engine emissions factors for use in estimating lateral compressor engine emissions for all major CENRAP basins.

| Basin | Rich-Burn Engine Emissions Factors [g/bhp-hr] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | NOx | CO | VOC | $PM_{10}$ | $H_2S$ | SOx | $CO_2$ | $CH_4$ |
| Anadarko Basin | 11.88 | 0.95 | 1.44 | 0.0095 | N/A | 0 | 110 | 0.23 |
| Arkoma Basin | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Cambridge Arch-Central Kansas Uplift | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Cherokee Platform Basin | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| East Texas Basin | 11.88 | 0.95 | 1.44 | 0.0095 | NA | 3.69 | 110 | 0.23 |
| Fort Worth Basin | 11.88 | 0.95 | 1.44 | 0.0095 | NA | 0 | 110 | 0.23 |
| Louisiana-Mississippi Salt Basins | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Nemaha Uplift | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Permian Basin | 11.88 | 0.95 | 1.44 | 0.0095 | NA | 14.19 | 110 | 0.23 |
| Southern Oklahoma Basin | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Western Gulf Basin | 11.88 | 0.95 | 1.44 | 0.0095 | NA | 0 | 110 | 0.23 |
| **Basin** | **Lean-Burn Engine Emissions Factors [g/bhp-hr]** | | | | | | | |
| | **NOx** | **CO** | **VOC** | $PM_{10}$ | $H_2S$ | **SOx** | $CO_2$ | $CH_4$ |
| Anadarko Basin | 3.22 | 1.77 | 1.73 | 0.038 | N/A | 0 | 110 | 1.45 |
| Arkoma Basin | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Cambridge Arch-Central Kansas Uplift | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Cherokee Platform Basin | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| East Texas Basin | 3.22 | 1.77 | 1.73 | 0.038 | NA | 3.69 | 110 | 1.45 |
| Fort Worth Basin | 3.22 | 1.77 | 1.73 | 0.038 | NA | 0 | 110 | 1.45 |
| Louisiana-Mississippi Salt Basins | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Nemaha Uplift | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Permian Basin | 3.22 | 1.77 | 1.73 | 0.038 | N/A | 14.19 | 110 | 1.45 |
| Southern Oklahoma Basin | N/A | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| Western Gulf Basin | 3.22 | 1.77 | 1.73 | 0.038 | N/A | 0 | 110 | 1.45 |

Data Sources

Engine operating parameters – and particularly the number of wells per lateral compressor and the fraction of wells using lateral compressors, by basin – were derived from survey data for most basins. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. As noted above, many basins do not have any significant usage of lateral compressors, as indicated in Table 9 with the entry "N/A".

Most engine emissions factors were obtained from the NMED ozone precursors study in Northwest New Mexico (Russell, et al., 2006), which contained an extensive database of emissions factors for a range of compressor engine makes/models. From this database average

rich-burn and lean-burn engine emissions factors were derived. $PM_{10}$, $CO_2$, and $CH_4$ emissions factors were obtained from AP-42 (EPA, 2000).

$SO_2$ emissions factors for lateral compressor engines are calculated using the $H_2S$ concentration in the fuel, similar to the method used for wellhead compressor engines.

**Artificial Lift (Pumpjack) Engines**

Methodology

Artificial lift engines (or pumpjacks) in this analysis refer specifically to engines located at oil wells to provide lift to the bring liquid from a well up to the wellhead. These engines are, from an emissions standpoint, very similar to wellhead compressor engines for gas wells in that they are usually small, natural gas-fired engines. Generally pumpjacks have smaller engines than wellhead compressor engines, but they are similarly in use almost constantly at oil wells. In basins with substantial numbers of oil wells, pumpjacks may be a significant NOx source category. Some pumpjack engines are electrified, if the electrical grid is located sufficiently near the oil field and if the economics of drawing electrical power make electrification attractive to the operators. If pumpjacks are electrified, their emissions are assumed to be zero.

The basic methodology for estimating emissions from a single non-electrified artificial lift engine is very similar to that of a wellhead compressor engine. The methodology is shown in Equation 5:

Equation (5) $$E_{engine} = \frac{EF_i \times HP \times LF \times t_{annual}}{907{,}185}$$

where:

- $E_{engine}$ are emissions from an artificial lift engine [ton/year/engine]
- $EF_i$ is the emissions factor of pollutant $i$ [g/hp-hr]
- $HP$ is the horsepower of the engine [hp]
- $LF$ is the load factor of the engine
- $t_{annual}$ is the annual number of hours the engine is used [hr/yr]

Extrapolation to Basin-Wide Emissions

Similarly to wellhead compressor engines, it is recommended that artificial lift engine emissions be scaled up to the basin level on the basis of well count. Using a scaling on the basis of oil production may understate the usage of artificial lift engines, since when oil fields are in decline these artificial lift engines may be increasingly used to provide the necessary lift to bring the product up to the wellhead. The methodology for scaling up artificial lift engine emissions is shown below in Equation 6:

Equation (6) $$E_{engine,TOTAL} = E_{engine} \times f_{pumpjack} \times \left(1 - e_{pumpjack}\right) \times W_{TOTAL}$$

where:

- $E_{engine,TOTAL}$ is the total emissions from artificial lift engines in the basin [ton/yr]
- $E_{engine}$ is the total emissions from an artificial lift engine (as shown in Equation 5) [ton/yr]
- $W_{TOTAL}$ is the total number of wells in the basin

$f_{pumpjack}$ is the fraction of oil wells with artificial lift engines
$e_{pumpjack}$ is the fraction of artificial lift engines that are electrified

County-level emissions would be estimated by allocating the total basin-wide artificial lift engine emissions into each county according to the fraction of basin wells located in each county.

Because it is not possible in all basins to provide well counts by well type (e.g. oil vs. gas wells) it is recommended that the total well count be used to scale artificial lift engine emissions. If more detailed oil and gas well databases that track wells by well type become available to CENRAP in the future, it is recommended that the scale-up methodology use a count of oil wells in the basin, rather than all wells in the basin.

Input Data

The recommended input data are presented below in Tables 11 and 12:

**Table 11**. Recommended engine operating parameters for use in estimating artificial lift engine (pumpjack) emissions for all major CENRAP basins.

| Basin | Typical Engine Operating Parameters | | | | |
|---|---|---|---|---|---|
| | Fraction of wells with artificial lift (pumpjack) engines | Rated Horsepower [hp] | Annual Activity [hrs] | Load Factor [%] | Fraction Electrified |
| Anadarko Basin | 1.00 | 25 | 8760 | 0.65 | 0.31 |
| Arkoma Basin | 1.00 | 13 | 8760 | 0.65 | 0.45 |
| Cambridge Arch-Central Kansas Uplift | 1.00 | 29 | 8760 | 0.65 | 0.97 |
| Cherokee Platform Basin | 1.00 | 23 | 8760 | 0.65 | 0.80 |
| East Texas Basin | 1.00 | 42 | 8760 | 0.65 | 0.00 |
| Fort Worth Basin | 1.00 | 15 | 8760 | 0.65 | 0.74 |
| Louisiana- Mississippi Salt Basins | 1.00 | N/A | N/A | N/A | 0.67 |
| Nemaha Uplift | 1.00 | 27 | 8760 | 0.65 | 0.87 |
| Permian Basin | 1.00 | 25 | 8760 | 0.65 | 1.00 |
| Southern Oklahoma Basin | 1.00 | 29 | 8760 | 0.65 | 0.97 |
| Western Gulf Basin | 1.00 | 60 | 8760 | 0.65 | 0.67 |

**Table 12**. Recommended engine emissions factors for use in estimating artificial lift engine emissions for all major CENRAP basins.

| Basin | Artificial Lift Engine Emissions Factors [g/bhp-hr] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | NOx | CO | VOC | $PM_{10}$ | $H_2S$ | SOx | $CO_2$ | $CH_4$ |
| Anadarko Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| Arkoma Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| Cambridge Arch-Central Kansas Uplift | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| Cherokee Platform Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| East Texas Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 3.69 | 631 | 30.5 |
| Fort Worth Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| Louisiana-Mississippi Salt Basins | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |

| Basin | Artificial Lift Engine Emissions Factors [g/bhp-hr] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | NOx | CO | VOC | $PM_{10}$ | $H_2S$ | SOx | $CO_2$ | $CH_4$ |
| Nemaha Uplift | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| Permian Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 14.19 | 631 | 30.5 |
| Southern Oklahoma Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |
| Western Gulf Basin | 11.99 | 40.93 | 1.28 | 0.05 | N/A | 0 | 631 | 30.5 |

Data Sources

Engine operating parameters were derived primarily from survey data for most basins. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. However for artificial lift engine load factor, most survey respondents were unable to provide any data on this parameter, and no literature survey data was obtained. Therefore the average artificial lift engine load factor derived from all basins studied in the IPAMS/WRAP Phase III work was used (Bar-Ilan, et al., 2008).

All engine emissions factors – except those for $SO_2$ – were obtained from the EPA's NONROAD model (EPA, 2005a), which contained default emissions factors for a natural gas-fired engine of the type considered here as an artificial lift engine. All pollutant species' emissions factors were obtained from the NONROAD model for the artificial lift engine source category. Since the NONROAD model was the only source of emissions factors for this source category, the same set of emissions factors is recommended for all basins.

$SO_2$ emissions factors for artificial lift engines are calculated using the $H_2S$ concentration in the fuel, similar to the method used for wellhead and lateral compressor engines.

**Drill Rigs – Drilling Operations**

Methodology

Drilling rigs are most commonly powered by one or more diesel-fired compression-ignition engines. These are configured in either a direct-drive configuration, or a diesel-electric configuration. In the former, the diesel engines are used to directly power specific activities of the drilling rig, and in the latter the diesel engines are used as generators to drive electric motors that power some or all of the activities of the drilling rig. In either case, there are three primary functions of these engines:

(1) Draw works – the draw works engine(s) provides power to the rotating drill bit and is responsible for the actual cutting operation of the rig
(2) Mud pumps – the mud pump engine(s) provides pumping of the working fluid (often referred to as "mud") into the bore hole for lubrication and cooling as well as pumping the spent fluid and debris material out of the bore hole
(3) Generators – the generator engine(s) provides power to the drilling crew and incidental power for the entire site operation (lighting, HVAC, crew quarters, etc.), or provides power to drive the draw works and pump motors in a diesel-electric configuration

Although there are three primary functions of the rig engines, there may be more than one of each engine type with the additional engines either required for additional horsepower or used as

back-up engines. Each of these three engine types is used for differing durations throughout a drilling process and is likely to have different load factors. In addition, each of the three engine types is likely to be of differing model years and hence Tier levels, since individual engines on rigs may be replaced on independent turnover schedules.

For purposes of this analysis, detailed information on individual rig configurations including the numbers of each engine type, model years of each engine type, load factors of each engine type and usage of each engine type was not available from survey data and could only be derived from the IPAMS/WRAP Phase III analysis (Bar-Ilan et al., 2008). However, survey data did indicate the average depth of drilling in each CENRAP basin, and so a total rig horsepower could be derived. The total rig horsepower was derived by scaling the average total rig horsepower from the WRAP Phase III work for a well of 8,000 ft depth by the ratio of the depth of wells in each CENRAP basin to this 8,000-ft benchmark. This scaling was done to reflect the assumption that deeper average well depths in a basin would require greater total rig horsepower. The well of 8,000 ft depth was chosen as a benchmark because in the WRAP Phase III analysis of the Denver-Julesburg Basin this was the average well depth for this particular basin, and the survey data collected for this basin provided the most detailed rig configuration data thus far in the Phase III project. This scaling to determine total rig horsepower is shown explicitly in Equation 7:

Equation (7) $$HP_{total,i} = HP_{total,D-J}\frac{D_{average,i}}{D_{average,D-J}}$$

where:

$HP_{total,i}$ is the total horsepower of all engines on the drilling rig in CENRAP basin *i* [hp]
$HP_{total,D\text{-}J}$ is the average total horsepower of all engines on a drilling rig in the Denver-Julesburg Basin [hp]
$D_{average,i}$ is the average well depth in CENRAP basin *i* [ft]
$D_{average,D\text{-}J}$ is the benchmark well depth in the Denver-Julesburg basin [8000 ft]

Since the exact engine configurations were not known for the CENRAP basins, it was determined to use only total horsepower and a single average load factor as derived from the WRAP Phase III analysis. All engines are conservatively assumed to be used for the duration of a drilling event.

Using the assumptions described above, emissions from a single drilling are determined according to Equation 8:

Equation (8) $$E_{drilling} = \frac{EF_i \times HP_{total} \times LF_{average} \times t_{drilling}}{907{,}185}$$

where:

$E_{drilling,engine}$ is the emissions from a drilling rig for drilling one well [ton/spud]
$EF_i$ is the emissions factor for all drilling rig engines for pollutant *i* [g/hp-hr]
$HP_{total}$ is the total horsepower of all engines on the drilling rig [hp]
$LF_{average}$ is the average load factor for all engines on the drilling rig
$t_{drilling}$ is the actual on-time of all engines on the drilling rig for a typical drilling event in the basin [hr/spud]

Extrapolation to Basin-Wide Emissions

Drilling emissions from a single spud are scaled to basin-wide emissions according to Equation 9:

Equation (9) $E_{drilling,TOTAL} = E_{drilling} \times S_{TOTAL}$

where:

$E_{drilling,TOTAL}$ is the total emissions in the basin from drilling activity [tons/yr]
$E_{drilling}$ is the total emissions in the basin from drilling a single well [tons/spud]
$S_{TOTAL}$ is the total number of spuds that occurred in the basin in 2002

County-level emissions would be estimated by allocating the total basin-wide drilling rig emissions into each county according to the fraction of total 2002 spuds that occurred in each county.

Input Data

The recommended input data are presented below in Tables 13 and 14:

**Table 13**. Recommended engine operating parameters for use in estimating drilling rig emissions for all major CENRAP basins.

| | Typical Engine Operating Parameters | | | | | |
|---|---|---|---|---|---|---|
| Basin | Average Well Depth [ft] | Duration of Drilling [hr] | Total Rig Horsepower [hp] | Load Factor [%] | Actual Engine On-Time [hr] | Engine BSFC [lb-fuel/bhp-hr] |
| Anadarko Basin | 13,750 | 1,080 | 4,720 | 0.67 | 261 | 0.367 |
| Arkoma Basin | 13,000 | 720 | 4,463 | 0.67 | 247 | 0.367 |
| Cambridge Arch-Central Kansas Uplift | 10,821 | 689 | 3,715 | 0.67 | 205 | 0.367 |
| Cherokee Platform Basin | 10,821 | 689 | 3,715 | 0.67 | 205 | 0.367 |
| East Texas Basin | 10,500 | 480 | 3,605 | 0.67 | 199 | 0.367 |
| Fort Worth Basin | 8,000 | 360 | 2,746 | 0.67 | 152 | 0.367 |
| Louisiana-Mississippi Salt Basins | 8,500 | 504 | 2,918 | 0.67 | 161 | 0.367 |
| Nemaha Uplift | 10,821 | 689 | 3,715 | 0.67 | 205 | 0.367 |
| Permian Basin | 7,000 | 480 | 2,403 | 0.67 | 133 | 0.367 |
| Southern Oklahoma Basin | 10,821 | 689 | 3,715 | 0.67 | 205 | 0.367 |
| Western Gulf Basin | 15,000 | 1,200 | 5,149 | 0.67 | 285 | 0.367 |

**Table 14**. Recommended engine emissions factors for use in estimating drill rig emissions for all major CENRAP basins.

| | Engine Emissions Factors [g/bhp-hr] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Basin | NOx | CO | VOC | $PM_{10}$ | $H_2S$ | SOx | $CO_2$ | $CH_4$ |
| Anadarko Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Arkoma Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Cambridge Arch-Central Kansas Uplift | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Cherokee Platform Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| East Texas Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Fort Worth Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |

| Basin | Engine Emissions Factors [g/bhp-hr] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | NOx | CO | VOC | $PM_{10}$ | $H_2S$ | SOx | $CO_2$ | $CH_4$ |
| Louisiana-Mississippi Salt Basins | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Nemaha Uplift | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Permian Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Southern Oklahoma Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |
| Western Gulf Basin | 8.00 | 5.00 | 1.26 | 1.00 | N/A | See below | 527 | 1.142 |

The $SO_2$ emissions factors are estimated using the brake-specific fuel consumption (BSFC) of the engine, from the US EPA's NONROAD model for a similarly sized drill rig engine, and the sulfur content of the off-road diesel fuel (EPA, 2005a). Using the NONROAD model guidance, for drilling rig engines the fraction of fuel sulfur that would form PM emissions is 2.2% of the sulfur content and it is assumed that the remaining sulfur in the fuel would be emitted as $SO_2$. Therefore the $SO_2$ emission factors in g/bhp-hr can be calculated using Equation 10:

Equation (10) $$EF_{SO_2} = \left( BSFC \times 453.6 \times (1 - soxcnv) - \left( {EF_{VOC}}/{1.053} \right) \right) \times 0.01 \times SOxdsl \times 2$$

where:

$EF_{SO_2}$ is the emissions factor of $SO_2$ for a drilling rig engine [g/bhp-hr]
*BSFC* is the brake-specific fuel consumption for a drilling rig engine [0.367 lb-fuel/bhp-hr]
*soxcnv* is the percentage of fuel sulfur by mass converted to PM [2.2%]
$EF_{VOC}$ is the VOC emissions factor for a drill rig engine [g/bhp-hr]
*SOxdsl* is the weight percent of sulfur in the off-road diesel fuel [%]

Individual CENRAP states can obtain the fuel sulfur content by county for each CENRAP state from the EPA's NONROAD model or other specific inventory modeling that these states have conducted.

Data Sources

As described above, the drilling rig total horsepower was derived from detailed data obtained as part of the development of basin-wide emissions for the Denver-Julesburg Basin in the IPAMS/WRAP Phase III work (Bar-Ilan, et al., 2008). The IPAMS/WRAP Phase III analysis was also used to determine an average load factor for all engines on a drilling rig. The average depth of wells in each basin as well as drilling duration information was obtained from surveys of the oil and gas companies. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. The BSFC of drilling rig engines was obtained from the EPA's NONROAD model (EPA, 2005a).

Emissions factors for all pollutants – except for $SO_2$ – were obtained from the EPA's NONROAD model for a drill rig engine (EPA, 2005a). Since engine age information was not available, this analysis conservatively considers all engines in the 2002 calendar year to be baseline uncontrolled engines for purposes of estimating emissions factors. This is consistent with information provided to ENVIRON by oil and gas companies on the average age of drill rig engines, since many of these engines are frequently rebuilt and can be in service for 20 years or

more before being replaced. As noted above, the $SO_2$ emissions factor must be estimated from the BSFC of the engine and the sulfur content of the off-road diesel fuel.

**Heaters**

Methodology

Heaters and boilers in use at oil and gas production facilities are generally natural gas-fired external combustors. They are typically used as either separator heaters (to provide heat input to the separators), or as tank heaters (to maintain tank temperatures). It should be noted that this source category considers only tank and separator heaters, not heaters or boilers used in dehydrators. This latter usage is covered under the dehydrator source category methodology description below.

Heaters are primarily considered an oil and gas NOx emissions source category, although they are also a minor source of CO, VOC and PM emissions. Heater emissions are calculated on the basis of the emissions factor of the heater, and the annual flow rate of gas to the heater. The annual gas flow rate is calculated from the BTU rating of the heater and the local BTU content of the gas. Although this may vary between oil and gas wells, the lack of information on well counts by well type requires the calculation for this analysis to consider heater configurations to be identical for all wells.

The basic methodology for estimating emissions for all pollutants except $SO_2$ for a single heater is shown in Equation 11:

Equation (11) $$E_{heater} = \frac{EF_{heater} \times Q_{heater} \times t_{annual} \times hc}{\left(HV_{local} \times 10^6 \times 2000\right)}$$

where:

- $E_{heater}$ is the emissions from a given heater [ton/yr]
- $EF_{heater}$ is the emission factor for a heater for a given pollutant [lb/million scf]
- $Q_{heater}$ is the heater MMBTU/hr rating [$MMBTU_{rated}$/hr]
- $HV_{local}$ is the local natural gas heating value [$MMBTU_{local}$/scf]
- $t_{annual}$ is the annual hours of operation [hr/yr]
- $hc$ is a heater cycling fraction to account for the fraction of operating hours that the heater is firing (if available)

The local heating value in Equation 11 refers to the fact that the volumetric heating value of the gas, expressed as [MMBTU/scf] varies with local gas composition.

The methodology for estimating $SO_2$ emissions from heaters requires first estimating the mass of gas combusted in the heater, and then uses the mass fraction of $H_2S$ in the gas and the assumption that all $H_2S$ is converted to $SO_2$. This methodology is described in Equation 12:

Equation (12) $$E_{heater,SO_2} = \frac{2 \times f_{H_2S}}{907200} \times \left( \frac{Q_{heater} \times t_{annual} \times hc}{\left(HV_{lcoal}\right)} \times \frac{P}{\left(\left(R/MW_{gas}\right) \times T \times 0.035\right)} \right)$$

where:

$E_{heater,SO_2}$ is the $SO_2$ emissions from a given heater [ton-$SO_2$/yr]

$f_{SO_2}$ is the mass fraction of $H_2S$ in the gas

$Q_{heater}$ is the heater MMBTU/hr rating [$MMBTU_{rated}$/hr]

$HV_{local}$ is the local natural gas heating value [$MMBTU_{local}$/scf]

$t_{annual}$ is the annual hours of operation [hr/yr]

$hc$ is a heater cycling fraction to account for the fraction of operating hours that the heater is firing (if available)

$P$ is atmospheric pressure [1 atm]

$R$ is the universal gas constant [0.082 L-atm/mol-K]

$MW_{gas}$ is the molecular weight of the gas [g/mol]

Extrapolation to Basin-Wide Emissions

Basin-wide heater emissions are estimated by determining the typical number of heaters per well and scaling up by well count. This is shown in Equation 13:

Equation (13) $$E_{heater,TOTAL} = \left(E_{heater} + E_{heater,SO_2}\right) \times N_{heater} \times W_{TOTAL} / 2000$$

where:

$E_{heater,TOTAL}$ is the total heater emissions in the basin [ton/yr]

$E_{heater}$ is the total emissions from a single heater [lb/yr]

$E_{heater,SO_2}$ is the total $SO_2$ emissions from a single heater [ton-$SO_2$/yr]

$W_{TOTAL}$ is the total number of wells in the basin

$N_{heater}$ is the typical number of heaters per well in the basin

County-level emissions are estimated by allocating the total basin-wide heater emissions into each county according to the fraction of basin total well counts that are located in each county. Again it should be noted that ideally a separate heater emissions calculation would be conducted for oil and gas wells and scaled up to the basin level by the count of each well type respectively. If a more detailed database of well counts by well type is made available to CENRAP in the future it is recommended that this methodology be modified to account for this change.

Input Data

The recommended input data are presented below in Tables 15 and 16:

**Table 15**. Recommended heater operating parameters for use in estimating heater emissions for all major CENRAP basins.

| | Typical Heater Operating Parameters | | | | |
|---|---|---|---|---|---|
| **Basin** | **Number of heaters in a typical well setup** | **Heater Firing Rate [MMBTU/hr]** | **Annual Activity [hrs]** | **Local Heating Value [MMBTU/scf]** | **Heater Cycling** |
| Anadarko Basin | 0.94 | 0.92 | 4601 | 1209 | 1 |
| Arkoma Basin | 0.5 | 1.19 | 2738 | 1209 | 1 |
| Cambridge Arch-Central Kansas Uplift | 0 | N/A | N/A | N/A | N/A |
| Cherokee Platform Basin | 0 | N/A | N/A | N/A | N/A |
| East Texas Basin | 0.95 | 0.64 | 2982 | 1209 | 1 |
| Fort Worth Basin | 1 | 0.5 | 4380 | 1209 | 1 |
| Louisiana- Mississippi | 0.95 | 0.67 | 2982 | 1209 | 1 |

| Basin | Typical Heater Operating Parameters | | | | |
|---|---|---|---|---|---|
| | Number of heaters in a typical well setup | Heater Firing Rate [MMBTU/hr] | Annual Activity [hrs] | Local Heating Value [MMBTU/scf] | Heater Cycling |
| Salt Basins | | | | | |
| Nemaha Uplift | 0.31 | 0.38 | 126 | 1209 | 1 |
| Permian Basin | 0.54 | 0.69 | 4121 | 1209 | 1 |
| Southern Oklahoma Basin | 0.63 | 0.38 | 574 | 1209 | 1 |
| Western Gulf Basin | 1.1 | 0.46 | 4297 | 1209 | 1 |

**Table 16**. Recommended heater emissions factors for use in estimating heater emissions for all major CENRAP basins.

| Basin | Heater Emissions Factors | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | NOx [lb/$10^6$-SCF] | CO [lb/$10^6$-SCF] | VOC [lb/$10^6$-SCF] | $PM_{10}$ [lb/$10^6$-SCF] | $H_2S$ Mass Fraction | $MW_{gas}$ [g/mol] | $CO_2$ [lb/$10^6$-SCF] | $CH_4$ [lb/$10^6$-SCF] |
| Anadarko Basin | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |
| Arkoma Basin | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |
| Cambridge Arch-Central Kansas Uplift | N/A | N/A | N/A | N/A | 0 | N/A | N/A | 2.3 |
| Cherokee Platform Basin | N/A | N/A | N/A | N/A | 0 | N/A | N/A | 2.3 |
| East Texas Basin | 100 | 84 | 5.5 | 7.6 | 0.01 | 23 | 12000 | 2.3 |
| Fort Worth Basin | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |
| Louisiana-Mississippi Salt Basins | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |
| Nemaha Uplift | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |
| Permian Basin | 100 | 84 | 5.5 | 7.6 | 0.03 | 26 | 12000 | 2.3 |
| Southern Oklahoma Basin | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |
| Western Gulf Basin | 100 | 84 | 5.5 | 7.6 | 0 | N/A | 12000 | 2.3 |

## Data Sources

Heater operating parameters were derived primarily from survey data for most basins. Where survey data was not available for a specific basin, the average of all CENRAP basins was used. The average local heating value could only be obtained from survey responses, since the CENRAP state OGCC's did not track any gas composition or thermochemical information. However, there were not sufficient responses to the request for local heating value data to be able to estimate this separately for each basin. Therefore the local heating value presented in Table 15 represents an average natural gas heating value obtained from the IPAMS/WRAP Phase III analysis (Bar-Ilan, et al., 2008).

All heater emissions factors were obtained from the EPA's AP-42 emissions factor database (EPA, 1998) for natural gas-fired heaters/boilers, under the external combustion sources category. As discussed above, heaters are primarily a NOx and CO source category with only minor emissions of other species, as shown in Table 16.

**Flaring**

Methodology

Flaring is used for a number of processes in the oil and gas industry to control VOC and other emissions from various processes. The three processes considered in this analysis which use flaring as a control process are stock tanks (condensate and oil), gas dehydration, and completion venting. For stock tanks, the flashing emissions from the tanks may be controlled by flaring, and for dehydrators the still vent emissions may be controlled by flaring. For completion venting, operators may use flares to control the emissions from raw vented gas during completion of a well. In each of these processes the vented or flashed gas is routed to a combustor which then burns the gas to remove upwards of 95% of VOC emissions. However, these flares are themselves a source of NOx and CO emissions. They are also potentially a source of $SO_2$ emissions if the flared gas contains $H_2S$. The control of VOC emissions from these 3 processes by use of flaring is covered separately in the methodology description for each process respectively.

The methodologies for estimating emissions from flaring vary depending on the process for which the flare is used. The methodologies for the three processes considered in this analysis are described below. Note that the flaring emissions methodologies are used to directly estimate basin-level flaring emissions, and thus no additional calculation is needed to extrapolate the emissions to the basin level. Note also that a separate methodology is used to estimate $SO_2$ emissions from flaring, as described below.

The methodology for estimating emissions from flaring of oil and condensate stock tank flash gas is described in Equation 14:

Equation (14) $$E_{flare,tank} = \left( \frac{EF_i \times Q_{flare,tank} \times HV}{1000} \times \frac{P_{basin,liquid}}{1000} \right) \Big/ 2000$$

where:

$E_{flare,tank}$ is the basin-wide flaring emissions from flaring of stock tank flash gas [ton/yr]
$EF_i$ is the emissions factor for pollutant $i$ [lb/MMBtu]
$Q_{flare,tank}$ is the volume of flash gas flared per unit of oil or condensate produced in the basin [MCF/1000 bbl]
$HV$ is the local heating value of the gas [BTU/scf]
$P_{basin,liquid}$ is the basin-wide oil or condensate production [bbl]

The methodology for estimating emissions from dehydration processes is described in Equation 15:

Equation (15) $$E_{flare,dehydration} = \left( \frac{EF_i \times Q_{flare,dehydrator} \times HV}{1000} \times \frac{P_{basin,gas}}{10^6} \right) \Big/ 2000$$

where:

$E_{flare,dehydration}$ is the basin-wide flaring emissions from flaring of dehydrator vent gas [ton/yr]
$EF_i$ is the emissions factor for pollutant $i$ [lb/MMBtu]

$Q_{flare,dehydrator}$ is the volume of dehydrator still vent gas flared per unit of gas produced in the basin [MCF/million MCF produced]
$HV$ is the local heating value of the gas [BTU/scf]
$P_{basin,gas}$ is the basin-wide gas production [MCF]

The methodology for estimating emissions from completion venting processes is described in Equation 16:

Equation (16) $$E_{flare,completion} = \left( \frac{EF_i \times Q_{flare,completion} \times HV}{1000} \times S_{basin} \right) \Big/ 2000$$

where:
$E_{flare,completion}$ is the basin-wide flaring emissions from flaring of completion vent gas [ton/yr]
$EF_i$ is the emissions factor for pollutant $i$ [lb/MMBtu]
$Q_{flare,completion}$ is the volume of completion venting gas flared per spud in the basin [MCF/spud]
$HV$ is the local heating value of the gas [BTU/scf]
$S_{basin}$ is the basin-wide spud count for calendar year 2002

Emissions of $SO_2$ occur if there is $H_2S$ present in the gas (i.e. sour gas). Emissions of $SO_2$ are estimated using the $H_2S$ mass fraction in the produced gas under the assumption that all $H_2S$ is converted to $SO_2$ in the flaring process. Given the limited information obtained on $H_2S$ concentrations, the same $H_2S$ concentration in produced gas is used as the $H_2S$ concentration in flared gas. For the completion venting and dehydrator venting processes, this assumption is accurate. For flash gas flaring, a separate flash gas composition analysis would need to be conducted to quantify the $H_2S$ content of the flash gas. A flash gas composition analysis was not available for this analysis. The methodology for estimating $SO_2$ emissions from flaring of oil and condensate flash gas is shown below in Equation 17:

Equation (17) $$E_{flare,tank,SO_2} = \left( \frac{P \times \left( Q_{flare,tank} \times P_{basin,liquid} / 1000 \right)}{\left( R / MW_{gas} \right) \times T \times 3.5 \times 10^{-5}} \right) \times f_{H_2S} \times 2 / 907200$$

where:
$E_{flare,tank,SO_2}$ is the basin-wide $SO_2$ flaring emissions from flaring of stock tank flash gas [ton/yr]
$P$ is atmospheric pressure [1 atm]
$Q_{flare,tank}$ is the volume of flash gas flared per unit of oil or condensate produced in the basin [MCF/1000 bbl]
$P_{basin,liquid}$ is the basin-wide oil or condensate production [bbl]
$R$ is the universal gas constant [0.082 L-atm/mol-K]
$MW_{gas}$ is the molecular weight of the flash gas [g/mol]
$T$ is the atmospheric temperature [298 K]
$f_{H_2S}$ is the mass fraction of $H_2S$ in the flash gas

The methodology for estimating $SO_2$ emissions from flaring of dehydrator vent gas is shown below in Equation 18:

Equation (18) $$E_{flare,dehydrator,SO_2} = \left( \frac{P \times \left(Q_{flare,dehydrator} \times P_{basin,gas} / 10^6\right)}{\left(R / MW_{gas}\right) \times T \times 3.5 \times 10^{-5}} \right) \times f_{H_2S} \times 2 / 907200$$

where:

$E_{flare,dehydrator,SO_2}$ is the basin-wide $SO_2$ flaring emissions from flaring of dehydrator vent gas [ton/yr]
$P$ is atmospheric pressure [1 atm]
$Q_{flare,dehydrator}$ is the volume of dehydrator still vent gas flared per unit of gas produced in the basin [MCF/million MCF produced]
$P_{basin,gas}$ is the basin-wide gas production [MCF]
$R$ is the universal gas constant [0.082 L-atm/mol-K]
$MW_{gas}$ is the molecular weight of the dehydrator venting gas [g/mol]
$T$ is the atmospheric temperature [298 K]
$f_{H_2S}$ is the mass fraction of $H_2S$ in the dehydrator venting gas

The methodology for estimating $SO_2$ emissions from flaring of completion vent gas is shown below in Equation 19:

Equation (19) $$E_{flare,completion,SO_2} = \left( \frac{P \times \left(Q_{flare,completion} \times S_{basin}\right)}{\left(R / MW_{gas}\right) \times T \times 3.5 \times 10^{-5}} \right) \times f_{H_2S} \times 2 / 907200$$

where:

$E_{flare,completion,SO_2}$ is the basin-wide $SO_2$ flaring emissions from flaring of completion vent gas [ton/yr]
$P$ is atmospheric pressure [1 atm]
$Q_{flare,completion}$ is the volume of completion venting gas flared per spud in the basin [MCF/spud]
$S_{basin}$ is the basin-wide spud count for calendar year 2002
$R$ is the universal gas constant [0.082 L-atm/mol-K]
$MW_{gas}$ is the molecular weight of the completion venting gas [g/mol]
$T$ is the atmospheric temperature [298 K]
$f_{H_2S}$ is the mass fraction of $H_2S$ in the completion venting gas

Extrapolation to Basin-Wide Emissions

As noted above, Equations 14-16 provide methodologies to estimate basin-wide flaring emissions from flaring of flash gas, dehydration vent gas, and completion vent gas for all pollutants except $SO_2$. Basin-wide emissions from all flaring activities are estimated according to Equation 20:

Equation (20) $E_{flare,TOTAL} = E_{flare,tank} + E_{flare,dehydration} + E_{flare,completion}$

where:

$E_{flare,TOTAL}$ is the total flaring emissions in the basin [ton/yr]
$E_{flare,tank}$ is the basin-wide flaring emissions from flaring of stock tank flash gas [ton/yr]
$E_{flare,dehydration}$ is the basin-wide flaring emissions from dehydrator venting [ton/yr]
$E_{flare,completion}$ is the basin-wide flaring emissions from completion venting [ton/yr]

Basin-wide emissions of $SO_2$ from flaring are estimated according to Equation 21:

Equation (21) $E_{flare,TOTAL,SO_2} = E_{flare,tank,SO_2} + E_{flare,dehydration,SO_2} + E_{flare,completion,SO_2}$

where:

$E_{flare,TOTAL,SO_2}$ is the total $SO_2$ flaring emissions in the basin [ton/yr]
$E_{flare,tank,SO_2}$ is the basin-wide $SO_2$ flaring emissions from flaring of stock tank flash gas [ton/yr]
$E_{flare,dehydrator,SO_2}$ is the basin-wide $SO_2$ flaring emissions from dehydrator venting [ton/yr]
$E_{flare,completion,SO_2}$ is the basin-wide $SO_2$ flaring emissions from completion venting [ton/yr]

County-level emissions are estimated by allocating the total basin-wide flaring emissions into each county according to the fraction of total surrogate (oil production, gas production, or spud counts for tank, dehydrator and completions, respectively) that are located in each county.

<u>Input Data</u>

The recommended input data are presented below in Tables 17 and 18:

**Table 17**. Recommended input data parameters for use in estimating flaring emissions for all major CENRAP basins.

| | Flaring Process: Oil and Condensate Tank Flash Gas Flaring | | |
|---|---|---|---|
| **Basin** | **Activity Surrogate** | **Gas Flared Per Unit of Activity Surrogate [MCF-flared/1000 bbl]** | **Heating Value of Flared Gas [BTU/SCF]** |
| Anadarko Basin | Liquid Production | 0.836 | 1655 |
| Arkoma Basin | Liquid Production | 0.836 | 1655 |
| Cambridge Arch-Central Kansas Uplift | Liquid Production | 0.836 | 1655 |
| Cherokee Platform Basin | Liquid Production | 0.836 | 1655 |
| East Texas Basin | Liquid Production | 0.836 | 1655 |
| Fort Worth Basin | Liquid Production | 0.836 | 1655 |
| Louisiana- Mississippi Salt Basins | Liquid Production | 0.836 | 1655 |
| Nemaha Uplift | Liquid Production | 0.836 | 1655 |
| Permian Basin | Liquid Production | 0.836 | 1655 |
| Southern Oklahoma Basin | Liquid Production | 0.836 | 1655 |
| Western Gulf Basin | Liquid Production | 0.836 | 1655 |
| | **Flaring Process: Dehydrator Vent Gas Flaring** | | |
| **Basin** | **Activity Surrogate** | **Gas Flared Per Unit of Activity Surrogate [MCF-flared/million MCF produced]** | **Heating Value of Flared Gas [BTU/SCF]** |
| Anadarko Basin | Gas Production | 8.84 | 1209 |
| Arkoma Basin | Gas Production | 8.84 | 1209 |

| Basin | Flaring Process: Oil and Condensate Tank Flash Gas Flaring | | |
|---|---|---|---|
| | Activity Surrogate | Gas Flared Per Unit of Activity Surrogate [MCF-flared/1000 bbl] | Heating Value of Flared Gas [BTU/SCF] |
| Cambridge Arch-Central Kansas Uplift | Gas Production | 8.84 | 1209 |
| Cherokee Platform Basin | Gas Production | 8.84 | 1209 |
| East Texas Basin | Gas Production | 8.84 | 1209 |
| Fort Worth Basin | Gas Production | 8.84 | 1209 |
| Louisiana- Mississippi Salt Basins | Gas Production | 8.84 | 1209 |
| Nemaha Uplift | Gas Production | 8.84 | 1209 |
| Permian Basin | Gas Production | 8.84 | 1209 |
| Southern Oklahoma Basin | Gas Production | 8.84 | 1209 |
| Western Gulf Basin | Gas Production | 8.84 | 1209 |
| Basin | Flaring Process: Completion Venting Gas Flaring | | |
| | Activity Surrogate | Gas Flared Per Unit of Activity Surrogate [MCF-flared/spud] | Heating Value of Flared Gas [BTU/SCF] |
| Anadarko Basin | Spuds | 13.4 | 1209 |
| Arkoma Basin | Spuds | 13.4 | 1209 |
| Cambridge Arch-Central Kansas Uplift | Spuds | 13.4 | 1209 |
| Cherokee Platform Basin | Spuds | 13.4 | 1209 |
| East Texas Basin | Spuds | 13.4 | 1209 |
| Fort Worth Basin | Spuds | 13.4 | 1209 |
| Louisiana- Mississippi Salt Basins | Spuds | 13.4 | 1209 |
| Nemaha Uplift | Spuds | 13.4 | 1209 |
| Permian Basin | Spuds | 13.4 | 1209 |
| Southern Oklahoma Basin | Spuds | 13.4 | 1209 |
| Western Gulf Basin | Spuds | 13.4 | 1209 |

**Table 18**. Recommended emissions factors for use in estimating flaring emissions for all major CENRAP basins.

| Basin | Flaring Emissions Factors | | | | | |
|---|---|---|---|---|---|---|
| | NOx [lb/MMBTU] | CO [lb/MMBTU] | $CO_2$ [lb/MMBTU] | $CH_4$ [lb/MMBTU] | $H_2S$ Mass Fraction | $MW_{gas}$ [g/mol] |
| Anadarko Basin | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Arkoma Basin | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Cambridge Arch-Central Kansas Uplift | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Cherokee Platform Basin | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| East Texas Basin | 0.068 | 0.37 | 102 | 0.022 | 0.01 | 23 |
| Fort Worth Basin | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Louisiana- Mississippi Salt Basins | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Nemaha Uplift | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Permian Basin | 0.068 | 0.37 | 102 | 0.022 | 0.03 | 26 |
| Southern Oklahoma Basin | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |
| Western Gulf Basin | 0.068 | 0.37 | 102 | 0.022 | 0 | N/A |

<u>Data Sources</u>

All input data parameters for estimating flaring emissions were derived from the IPAMS/WRAP Phase III work (Bar-Ilan, et al., 2008), with the exception of $H_2S$ mass fraction and gas molecular weight, which were derived from survey responses. Note that the survey responses

only indicated significant $H_2S$ mass fractions in the produced gas for two basins: the Permian and East Texas Basins. It is recommended that these values be revised for all basins if CENRAP is able to obtain more detailed gas composition analyses in the future.

Flaring emissions factors for NOx, CO, $CO_2$ and $CH_4$ were obtained from EPA's AP-42 compendium of emissions factors (EPA, 1991).

**Oil and Condensate Tanks**

Methodology

Oil and condensate tanks are expected to be one of the most significant sources of VOC emissions from oil and gas area source categories throughout the CENRAP region. Oil and condensate tanks are used to store produced liquid at individual well sites and there may be many thousands of such storage tanks throughout a basin. Two primary processes create emissions of gas from oil and condensate tanks: (1) flashing, whereby condensate brought from downhole pressure to atmospheric pressure may experience a sudden volatilization of some of the condensate; and (2) working and breathing losses, whereby some volatilization of stored product occurs through valves and other openings in the tank battery over time. Note that flashing emissions are associated with condensate tanks, whereas working and breathing losses are associated with both oil and condensate tanks. Both flash gas and emitted gas from working and breathing losses are expected to have a different composition from gas directly produced at the well. In most cases this flash gas is likely to have a composition of volatile species that is heavier than produced gas. Very few direct measurements of gas composition from working and breathing losses have been taken, and thus this analysis assumes that the gas compositions from both loss processes are identical. It should be noted that no information could be obtained on the sulfur content of the flash gas or working and breathing losses, and thus this analysis does not consider sulfur emissions from tanks. One possible control strategy for eliminating flashing and working and breathing losses from tanks is to route liquid production directly into a pipeline, essentially eliminating the use of tanks.

Methodologies are presented below for estimating condensate tank and oil tank emissions. Note that condensate production totals are not available for all basins in this analysis, however if this information becomes available to CENRAP in the future the methodologies here could be used for estimating emissions from both condensate and oil tanks. The emissions factors for oil and condensate production are derived from running a process modeling software that predicts the volume of flash gas or working and breathing losses from the tank per unit of production. The process modeling software, such as GRI GLYCalc or HYSYS, requires input data about tank configuration, size and environmental conditions. These emissions factors are typically developed by oil and gas companies, or state environmental agencies.

The methodology for estimating oil tank emissions is shown below in Equation 21:

Equation (21) $$E_{oil,tanks} = \frac{P_{oil,tanks} \times EF_{oil,tanks}}{2000} \times f_{tank,oil} \times \left(1 - 0.98c_{oil,tanks}\right)$$

where:

$E_{oil,tanks}$ is the basin-wide emissions from oil tanks [tons/yr]

$EF_{oil,tanks}$ is the derived VOC emissions factor for working and breathing losses from oil tanks [lb-VOC/bbl]
$P_{oil,tanks}$ is the basin-wide oil production [bbl]
$f_{tank,oil}$ is the fraction of oil production that is routed to tanks
$c_{oil,tanks}$ is the fraction of oil production at tanks that are equipped with flares to control VOC emissions

The methodology for estimating condensate tank emissions is shown below in Equation 22:

Equation (22) $$E_{condensate,tanks} = \frac{P_{condensate,tanks} \times EF_{condensate,tanks}}{2000} \times f_{tank,condensate} \times \left(1 - 0.98 c_{condensate,tank}\right)$$

where:
$E_{condensate,tanks}$ is the basin-wide emissions from condensate tanks [tons/yr]
$EF_{condensate,tank}$ is the derived VOC emissions factor for flashing and working and breathing losses from condensate tanks [lb-VOC/bbl]
$P_{condensatetanks}$ is the condensate production from gas wells thoughput [bbl]
$f_{tank,condensate}$ is the fraction of condensate production that is routed to tanks
$c_{condensate,tanks}$ is the fraction of condensate production at tanks that are equipped with flares to control VOC emissions

Extrapolation to Basin-Wide Emissions

Equations 21 and 22 provide methodologies to directly estimate basin-wide oil and condensate tank emissions, respectively.

County-level oil tank emissions are estimated by allocating the total basin-wide oil tank emissions into each county according to the fraction of total 2002 oil production occurring in that county. County-level condensate tank emissions would be estimated by allocating the total basin-wide condensate tank emissions into each county according to the fraction of total 2002 condensate production occurring in that county.

Input Data

The recommended input data are presented below in Table 19:

**Table 19**. Recommended input data parameters for use in estimating working & breathing and flashing emissions from oil and condensate tanks in all major CENRAP basins.

| | OIL TANKS | | | CONDENSATE TANKS | | |
|---|---|---|---|---|---|---|
| Basin | Fraction of Production to Tanks | Emissions Factor [lb-VOC/bbl] | Fraction Flared | Fraction of Production to Tanks | Emissions Factor [lb-VOC/bbl] | Fraction Flared |
| Anadarko Basin | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| Arkoma Basin | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| Cambridge Arch-Central Kansas Uplift | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| Cherokee Platform Basin | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| East Texas Basin | 100% | 1.60 | 25% | 100% | 33.30 | 25% |
| Fort Worth Basin | 100% | 1.60 | 25% | 100% | 33.30 | 25% |
| Louisiana- Mississippi Salt Basins | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| Nemaha Uplift | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| Permian Basin | 100% | 1.60 | 25% | 100% | 33.30 | 25% |
| Southern Oklahoma Basin | 100% | 2.94 | 0% | 100% | 13.86 | 0% |
| Western Gulf Basin | 100% | 1.60 | 25% | 100% | 33.30 | 25% |

Data Sources

Information collected about oil and condensate tanks from the industry survey effort was very limited and did not provide usable data. It was conservatively assumed that all production would be routed to tanks. The fraction of tank production that is flared was obtained from the TCEQ's 2005 oil and gas inventory (Pendleton, et al., 2008). Emissions factors for flashing and working and breathing losses for oil and condensate tanks were obtained from the IPAMS/WRAP Phase III work (Bar-Ilan, et al., 2008) for all basins except the Texas basins (East Texas Basin, Fort Worth Basin, Permian Basin, and Western Gulf Basin). Emissions factors for flashing and working and breathing losses for tanks in the Texas basins was obtained from TCEQ's 2005 oil and gas inventory calculations (Pendleton, et al., 2008). Given the variability in oil and condensate composition from basin to basin, it is recommended that CENRAP revise these emissions factors if more detailed basin-level data on tank emissions factors becomes available in the future.

**Dehydrators**

Methodology

Dehydrators are devices used to remove excess water from produced natural gas prior to transmission into a pipeline or to a gas processing facility. These wellhead devices are normally only used in regions where there are significant concentrations of water in the gas that cannot be removed by separators. Thus their usage is highly localized depending on the composition of the gas. There are both liquid dessicant and solid dessicant dehydrators, but in practice liquid dessicant dehydrators are overwhelmingly used. The liquid dessicant is typically either glycol, diethylene glycol (DEG) or triethylene glycol (TEG). Glycol dehydrators have two emissions sources: the still vent from which some fugitive gas is emitted; and the reboiler which is essentially a heater and has similar emissions characteristics to a heater. For both still vent and heater emissions from dehydrators, emissions factors are typically developed using the process simulation software GLYCalc, developed by the Gas Research Institute. The survey effort in Task 2b did not yield usable information to generate per-dehydrator or per-unit production emissions factors for dehydrator still vents and reboilers, and therefore broad regional emissions factors per unit production from the IPAMS/WRAP Phase III work are used in this analysis (except for the Texas Basins, where NETAC and TCEQ data are available on dehydrators). For still vents the only emissions factors available from the IPAMS/WRAP Phase III work are for VOC and not for other pollutants. For reboilers emissions of NOx, and CO are available. These per-unit production emissions factors can be used to directly estimate basin-level dehydrator emissions.

The basic methodology for estimating basin-wide emissions from dehydrator still vents is shown in Equation 23:

Equation (23) $$E_{stillvent} = \frac{EF_{stillvent} \times P_{basin}}{2 \times 10^6}$$

where:

$E_{stillvent}$ is the basin-wide emissions from dehydrator still vents [ton-VOC/yr]

$EF_{stillvent}$ is the emission factor for a still vent per unit production [lb/MMSCF]

$P_{basin}$ is the basin-wide gas production [MCF/yr]

The basic methodology for estimating basin-wide emissions from dehydrator reboilers is similar to that for still vents, and is shown in Equation 24:

Equation (24) $$E_{reboiler} = \frac{EF_{reboiler} \times P_{basin}}{2 \times 10^6}$$

where:

$E_{stillvent}$ is the basin-wide emissions from dehydrator reboilers [ton/yr]
$EF_{stillvent}$ is the emission factor for a dehydrator reboiler per unit production [lb/MMSCF]
$P_{basin}$ is the basin-wide gas production [MCF/yr]

Extrapolation to Basin-Wide Emissions

Equations 23 and 24 already provide direct estimates of the VOC, NOx, CO, $CO_2$ and $CH_4$ emissions from dehydrator still vents and reboilers, respectively. Total basin emissions from dehydrators would then be estimated according to Equation 25:

Equation (25) $$E_{dehydrator,TOTAL} = E_{stillvent} + E_{reboiler}$$

where:

$E_{dehydrator,TOTAL}$ is the total dehydrator emissions in the basin [ton/yr]
$E_{stillvent}$ is the total dehydrator still vent emissions in the basin [ton-VOC/yr]
$E_{reboiler}$ is the total dehydrator reboiler emissions in the basin [ton/yr]

County-level dehydrator emissions are estimated by allocating the total basin-wide dehydrator emissions into each county according to the fraction of total 2002 gas production that is located in each county.

Input Data

The recommended input data are presented below in Table 20:

**Table 20**. Recommended emissions factors for use in estimating dehydrator emissions for all major CENRAP basins.

| Basin | Dehydrator Emissions Factors | | |
|---|---|---|---|
| | NOx [lb/MMSCF] | CO [lb/MMSCF] | VOC [lb/MMBTU] |
| Anadarko Basin | 0.052 | 0.105 | 2.622 |
| Arkoma Basin | 0.052 | 0.105 | 2.622 |
| Cambridge Arch-Central Kansas Uplift | 0.052 | 0.105 | 2.622 |
| Cherokee Platform Basin | 0.052 | 0.105 | 2.622 |
| East Texas Basin | 0.052 | 0.105 | 2.622 |
| Fort Worth Basin | 0.052 | 0.105 | 2.622 |
| Louisiana- Mississippi Salt Basins | 0.052 | 0.105 | 5.5 |
| Nemaha Uplift | 0.052 | 0.105 | 5.5 |
| Permian Basin | 0.052 | 0.105 | 2.622 |
| Southern Oklahoma Basin | 0.052 | 0.105 | 5.5 |
| Western Gulf Basin | 0.052 | 0.105 | 2.622 |

Data Sources

Only the IPAMS/WRAP Phase III analysis (Bar-Ilan, et al., 2008) was able to provide broadly applicable still vent and reboiler emissions factors per unit of production for all major CENRAP basins except the Texas basins. For the East Texas Basins, the still vent VOC emissions factors from the NETAC study (Pollution Solutions, 2005) were used and for the remainder of the Texas basins the TCEQ oil and gas area source inventory (Pendleton, et al., 2008) was used.

**Well Completions**

Methodology

Once drilling and other well construction activities are finished, a gas well must be completed in order to begin producing gas. The completion process requires venting of the well for a sustained period of time to remove mud and other solid debris in the well, to remove any inert gas used to stimulate the well (such as $CO_2$ and/or $N_2$) and to bring the gas composition to pipeline grade. During this process significant amounts of gas may be vented, and this gas can be a VOC emissions source, as well as an $H_2S$ emissions source if there is significant $H_2S$ present in the gas. In general this analysis assumes that the composition of the completion venting gas is identical to production gas, because no detailed information is available on the completion venting gas specifically.

Emissions from well completions are estimated on the basis of the volume of gas vented during completion and the average VOC content of that gas, obtained from gas composition analyses. Flaring and/or green completion practices may be used to control emissions from the completion process. Flaring typically has 98% control efficiency for VOC emissions, and green completion practices have a range of control efficiencies depending on the amount of vented gas that is captured during the process.

The calculation methodology for estimating emissions from a single completion event is shown below in Equation 26:

Equation (26) $$E_{completion,i} = \left( \frac{P \times (V_{vented})}{\left( R/MW_{gas} \right) \times T \times 3.5 \times 10^{-5}} \right) \times \frac{f_i}{907200}$$

where:

$E_{completion,i}$ is the emissions of pollutant *i* from a single completion event [ton/event]
$P$ is atmospheric pressure [1 atm]
$V_{vented}$ is the volume of vented gas per completion [MCF/event]
$R$ is the universal gas constant [0.082 L-atm/mol-K]
$MW_{gas}$ is the molecular weight of the gas [g/mol]
$T$ is the atmospheric temperature [298 K]
$f_i$ is the mass fraction of pollutant *i* in the completion venting gas

Extrapolation to Basin-Wide Emissions

The total emissions from all completions occurring in a basin are evaluated following Equation 27:

Equation (27) $E_{completion,TOTAL} = E_{completion,i} \times S_{basin} \times \left(1 - 0.98c_{flare} - c_{green}\right)$

where:

$E_{completion,TOTAL}$ are the total emissions basin-wide from completions [tons/year]
$E_{completion,i}$ are the completion emissions from a single completion event [tons/event]
$c_{flare}$ is the fraction of completions in the basin that were controlled by flares
$c_{green}$ is the fraction of completions in the basin that were controlled by green completion techniques
$S_{basin}$ is the basin-wide spud count for calendar year 2002

County-level emissions are estimated by allocating the total basin-wide completion emissions into each county according to the fraction of 2002 well count occurring in that county.

Input Data

The recommended input data are presented below in Table 21:

**Table 21**. Recommended input data parameters for use in estimating completion venting emissions in all major CENRAP basins.

| Basin | Typical Completion Venting Parameters | | |
|---|---|---|---|
| | Volume of Gas Vented Per Completion [MCF/event] | Fraction of Completions Flared | Fraction of Completions with Green Completion |
| Anadarko Basin | 1,737 | 0 | 0 |
| Arkoma Basin | 31 | 0 | 0 |
| Cambridge Arch-Central Kansas Uplift | 0 | 0 | 0 |
| Cherokee Platform Basin | 637 | 0 | 0 |
| East Texas Basin | 2,417 | 0 | 0 |
| Fort Worth Basin | 637 | 0 | 0 |
| Louisiana- Mississippi Salt Basins | 333 | 0 | 0 |
| Nemaha Uplift | 0 | 0 | 0 |
| Permian Basin | 0 | 0 | 0 |
| Southern Oklahoma Basin | 18 | 0 | 0 |
| Western Gulf Basin | 1,200 | 0 | 0 |

Pollutant mass fractions used in estimating completion venting emissions are presented in the combined natural gas composition data provided in the master data matrix spreadsheet accompanying this report. This composition data is too extensive to present here for all major CENRAP basins.

Data Sources

Completion venting volumes per completion event for each basin were obtained from surveys, or where unavailable an average of all CENRAP basins was used. VOC mass fractions of produced

gas were obtained from survey data or where unavailable an average of all CENRAP basins was used.

**Well Blowdowns**

Methodology

Well blowdowns refer to the practice of venting gas from wells that have developed some kind of cap or obstruction before any additional intervention work can be done on the wells. Typically well blowdowns are conducted on wells that have been shut in for a period of time and the operator desires to bring the well back into production. Well blowdowns are also sometimes conducted to remove fluid caps that have built up in producing gas wells. Because gas is directly vented from the blowdown event, blowdowns can be a source of VOC emissions. In addition, if there is a significant concentration of $H_2S$ in the gas, blowdowns can also be a source of $H_2S$ emissions.

Emissions from blowdowns are estimated on the basis of the volume of gas vented during a blowdown and the average pollutant content of that gas, obtained from gas composition analyses. This methodology is very similar to that of completion venting. Flaring and/or green practices may be used to control emissions from the blowdown process. Flaring typically has a 98% control efficiency for VOC emissions, and green practices have a range of control efficiencies depending on the amount of vented gas that is captured during the process.

The calculation methodology for estimating emissions from a single blowdown event is shown below in Equation 28:

Equation (28) $$E_{blowdown,i} = \left( \frac{P \times (V_{vented})}{\left( R / MW_{gas} \right) \times T \times 3.5 \times 10^{-5}} \right) \times \frac{f_i}{907200}$$

where:

- $E_{blowdown,i}$ is the emissions of pollutant $i$ from a single blowdown event [ton/event]
- $P$ is atmospheric pressure [1 atm]
- $V_{vented}$ is the volume of vented gas per blowdown [MCF/event]
- $R$ is the universal gas constant [0.082 L-atm/mol-K]
- $MW_{gas}$ is the molecular weight of the gas [g/mol]
- $T$ is the atmospheric temperature [298 K]
- $f_i$ is the mass fraction of pollutant $i$ in the vented gas

Extrapolation to Basin-Wide Emissions

The total emissions from all blowdowns occurring in a basin are evaluated following Equation 29:

Equation (29) $$E_{blowdown,TOTAL} = E_{blowdown,i} \times N_{blowdown} \times N_{wells} \times (1 - 0.98 c_{flare} - c_{green})$$

where:

$E_{blowdown,TOTAL}$ are the total emissions basin-wide from blowdowns [tons/year]
$E_{blowdown,i}$ are the blowdown emissions from a single blowdown event [tons/event]
$c_{flare}$ is the fraction of blowdowns in the basin that were controlled by flares
$c_{green}$ is the fraction of blowdowns in the basin that were controlled by green techniques
$N_{blowdown}$ is the number of blowdowns per well in the basin
$N_{wells}$ is the total number of active wells in the basin in calendar year 2002

County-level emissions are estimated by allocating the total basin-wide blowdown emissions into each county according to the fraction of 2002 well count occurring in that county.

Input Data

The recommended input data are presented below in Table 22:

**Table 22**. Recommended input data parameters for use in estimating blowdown emissions in all major CENRAP basins.

| Basin | Typical Blowdown Parameters | | | |
|---|---|---|---|---|
| | **Blowdown Frequency [events/well/year]** | **Volume of Gas Vented Per Blowdown Per Well [MCF/event/well]** | **Fraction of Blowdowns Flared** | **Fraction of Blowdowns with Green Techniques** |
| Anadarko Basin | 3.3 | 7.28 | 0 | 0 |
| Arkoma Basin | 0.18 | 7.22 | 0 | 0 |
| Cambridge Arch-Central Kansas Uplift | 0 | 0 | N/A | N/A |
| Cherokee Platform Basin | 0.19 | 7.22 | 0 | 0 |
| East Texas Basin | 1.09 | 31.67 | 0 | 0 |
| Fort Worth Basin | 1.54 | 38.90 | 0 | 0 |
| Louisiana- Mississippi Salt Basins | 1.09 | 31.67 | 0 | 0 |
| Nemaha Uplift | 0.74 | 2.30 | 0 | 0 |
| Permian Basin | 5 | 50 | 0 | 0 |
| Southern Oklahoma Basin | 0 | 0 | N/A | N/A |
| Western Gulf Basin | 0.71 | 173.90 | 0 | 0 |

Pollutant mass fractions used in estimating well blowdown emissions are presented in the combined natural gas composition data provided in the master data matrix spreadsheet accompanying this report. This composition data is too extensive to present here for all major CENRAP basins.

Data Sources

Number of blowdowns per well per year and the volume of gas vented per blowdown for each basin were obtained from surveys, or where unavailable an average of all CENRAP basins was used. Pollutant mass fractions of produced gas were obtained from survey data or where unavailable an average of all CENRAP basins was used.

**Fugitive Emissions (Leaks)**

Methodology

Fugitive emissions refer to emissions of produced gas through connectors, flanges, valves and other pipeline hardware at the wellhead. These emissions are essentially leaks that result from

high-pressure gas moving through the various hardware components of a wellhead assembly. It should be noted that this source category is distinct from fugitive emissions from pipelines, which are not considered here, and refers only to components located at wellheads. Because the fugitive emissions are produced gas, this source category can be a source of VOC emissions. In addition, if the gas contains significant concentrations of $H_2S$ then this source category can also be a source of $H_2S$ emissions.

Fugitive emissions from wellheads are estimated using AP-42 emissions factors (EPA, 1995) and component counts for typical well setups. The well setup is typically characterized by the type of equipment installed and by the type of service to which the equipment applies – gas, light liquid, heavy liquid, or water.

Fugitive emissions for an individual typical well are estimated according to Equation 30:

Equation (30) $$E_{fugitive,j} = \sum_i EF_i \times N_i \times t_{annual} \times Y_j \times 0.0011$$

where:

$E_{fugitive}$ is the fugitive emissions for a single typical well for pollutant $j$ [ton/yr/well]
$EF_i$ is the emission factor of TOC for a single component $i$ [kg/hr/component]
$N_i$ is the total number of components of type $i$
$t_{annual}$ is the annual number of hours the well is in operation [8760 hr/yr]
$Y_j$ is the mass fraction of pollutant $j$ to TOC in the vented gas

Extrapolation to Basin-Wide Emissions

Basin-wide fugitive emissions are estimated according to Equation 31:

Equation (31) $$E_{fugitive,TOTAL} = E_{fugitive,j} \times N_{well}$$

where:

$E_{fugitive,TOTAL}$ is the total fugitive emissions in the basin [ton/yr]
$E_{fugitive,j}$ is the fugitive emissions for a single well of pollutant $j$ [ton/yr]
$N_{well}$ is the total number of active wells in the basin for calendar year 2002

County-level fugitive emissions are estimated by allocating the total basin-wide fugitive emissions into each county according to the fraction of 2002 well count occurring in that county.

Input Data

The recommended input data are presented below in Tables 23 and 24:

**Table 23**. Recommended fugitive component emissions factors for use in estimating fugitive emissions in all major CENRAP basins.

| Equipment Type | Emissions Factors [kg-TOC/hr] | | | |
|---|---|---|---|---|
| | Gas | Heavy Oil | Light Oil | Water/Oil |
| Valves | 0.0045 | 0.0000084 | 0.0025 | 0.000098 |
| Pump Seals | 0.0024 | N/A | 0.013 | 0.000024 |
| Others | 0.0088 | 0.000032 | 0.0075 | 0.014 |
| Connectors | 0.0002 | 0.0000075 | 0.00021 | 0.00011 |
| Flanges | 0.00039 | 0.00000039 | 0.00011 | 0.0000029 |
| Open-ended Lines | 0.002 | 0.00014 | 0.0014 | 0.00025 |

The fractions of pollutants to TOC in the gas, used in estimating fugitive emissions, are presented in the combined natural gas composition data provided in the master data matrix spreadsheet accompanying this report. This composition data is too extensive to present here for all major CENRAP basins.

<u>Data Sources</u>

The number of devices by service type per well for a typical well in each basin were obtained from survey data, or where unavailable an average of all CENRAP basins was used. Emissions factors in kg-TOC/hr/device were obtained from EPA AP-42 emissions factor documentation (EPA, 1995). Note that these emissions rates are evaluated at standard temperature and pressure (STP). Fugitive emissions rates in TOC equivalent should be corrected for temperatures and pressures if significantly different from STP.

**Table 24.** Recommended number of fugitive components per typical well by component service type in all major CENRAP basins.

| Device Type | Service | Number of Components Per Typical Well | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Louisiana Mississippi Salt Basins | Southern Oklahoma Basin | Nemaha Uplift | Arkoma Basin | Cambridge Arch Central Kansas Uplift | Fort Worth Basin | Cheroke e Platform | Permian Basin | East Texas Basin | Western Gulf Basin | Anadarko Basin |
| Valves | Gas | 12 | 15 | 15 | 12 | 15 | 12 | 15 | 19 | 12 | 24 | 12 |
| Valves | Heavy Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Valves | Light Oil | 20 | 19 | 19 | 20 | 19 | 20 | 19 | 16 | 20 | 18 | 20 |
| Valves | Water/Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pump Seals | Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pump Seals | Heavy Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pump Seals | Light Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pump Seals | Water/Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Others | Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Others | Heavy Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Others | Light Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Others | Water/Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Connectors | Gas | 35 | 48 | 48 | 35 | 48 | 35 | 48 | 43 | 35 | 118 | 35 |
| Connectors | Heavy Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Connectors | Light Oil | 90 | 86 | 86 | 90 | 86 | 90 | 86 | 58 | 90 | 95 | 90 |
| Connectors | Water/Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Flanges | Gas | 18 | 25 | 25 | 18 | 25 | 18 | 25 | 29 | 18 | 59 | 18 |
| Flanges | Heavy Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Flanges | Light Oil | 0 | 5 | 5 | 0 | 5 | 0 | 5 | 12 | 0 | 25 | 0 |
| Flanges | Water/Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Open-ended Lines | Gas | 6 | 5 | 5 | 6 | 5 | 6 | 5 | 3 | 6 | 3 | 6 |
| Open-ended Lines | Heavy Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Open-ended Lines | Light Oil | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 3 | 2 | 3 |
| Open-ended Lines | Water/Oil | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Pneumatic Control Devices**

Methodology

Pneumatic devices are those devices used for a variety of wellhead processes which are powered mechanically by high-pressure produced gas as the working fluid – i.e. pneumatically-powered devices. This is necessary for many remote well sites where electrical grid power is not available to power these devices. Typical pneumatic devices include pressure transducers, liquid level controllers, pressure controllers and positioners. These devices are typically in operation continuously throughout the year. All of these devices vent or leak the working fluid, which is produced gas, and are therefore a source of VOC emissions. If the gas contains a significant concentration of $H_2S$, these devices can also be a source of $H_2S$ emissions. Like fugitive emissions, the emissions from these devices are typically estimated by obtaining a configuration of a typical well, including the count of devices by type at the typical well. Emissions rates of gas from these pneumatic devices have been studied extensively by the EPA as part of the Natural Gas Star program (EPA, 2004), which are the source of quantitative emissions factors for pneumatic devices in this analysis.

The methodology for estimating the emissions from pneumatic devices for a single typical well is shown in Equation 32:

Equation (32) $$E_{pneumatic,j} = \frac{f_j}{907200}\left(\sum_i \dot{V}_i \times N_i \times t_{annual}\right) \times \frac{P}{\left(\left(R/MW_{gas}\right) \times T \times 3.5 \times 10^{-5}\right)}$$

where:

$E_{pneumatic,j}$ is the total emissions of pollutant $j$ from all pneumatic devices for a typical well [ton/year/well]

$\dot{V}_i$ is the volumetric bleed rate from device $i$ [MCF/hr/device]

$N_i$ is the total number of device <u>*i*</u> owned by the participating companies

$t_{annual}$ is the number of hours per year that devices were operating [8760 hr/yr]

$P$ is the atmospheric pressure [1 atm]

$R$ is the universal gas constant [0.082 L-atm/mol-K]

$MW_{gas}$ is the molecular weight of the gas [g/mol]

$T$ is the atmospheric temperature [298 K]

$f_j$ is the mass fraction of pollutant $j$ in the vented gas

Extrapolation to Basin-Wide Emissions

Basin-wide pneumatic device emissions were estimated according to Equation 33:

Equation (33) $$E_{pneumatic,TOTAL} = E_{pneumatic,j} \times N_{well}$$

where:

$E_{pneumatic,TOTAL}$ is the total pneumatic device emissions of pollutant $j$ in the basin [ton/yr]

$E_{pneumatic,j}$ is the pneumatic device emissions of pollutant $j$ for a single typical well [ton/yr/well]

$N_{well}$ is the total number of active wells in the basin for calendar year 2002

County-level emissions are estimated by allocating the total basin-wide pneumatic emissions into each county according to the fraction of 2002 well count occurring in that county.

Input Data

The recommended input data are presented below in Table 25:

**Table 25**. Recommended pneumatic device input data for use in estimating pneumatics emissions in all major CENRAP basins.

| Basin | | Device Type | | | | |
|---|---|---|---|---|---|---|
| | | Liquid Level Controller | Positioner | Pressure Controller | Transducer | Other |
| Anadarko Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Arkoma Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Cambridge Arch Central Kansas Uplift | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Cherokee Platform Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| East Texas Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Fort Worth Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Louisiana Mississippi Salt Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Nemaha Uplift | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Permian Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Southern Oklahoma Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |
| Western Gulf Basin | No. of Devices | 2 | 0 | 1 | 0 | 0 |
| | Bleed Rate [SCF/hr] | 31 | 15.2 | 16.8 | 13.6 | 0 |

Pollutant mass fractions used in estimating pneumatic device emissions are presented in the combined natural gas composition data provided in the master data matrix spreadsheet accompanying this report. This composition data is too extensive to present here for all major CENRAP basins.

Data Sources

The number of pneumatic devices by device type per well for a typical well in each basin were obtained from survey data, or where unavailable an average of all CENRAP basins was used. Bleed rates in [scf/hr/device] were obtained from data gathered as part of EPA's Natural Gas Star Program (EPA, 2004). Note that these bleed rates are evaluated at standard temperature and pressure (STP). Pneumatic emissions should be corrected for temperatures and pressures if significantly different from STP.

**Natural Gas Composition**

Data on the chemical composition of the natural gas produced in the major CENRAP basins was obtained primarily from surveys, although where unavailable for a particular basin an average of all CENRAP basins was used. This data is needed to estimate emissions from a number of source categories, particularly the direct venting source categories, and is needed to estimate $SO_2$ emissions where there is a significant concentration of $H_2S$ in the gas. Because of the extensive nature of these compositions for all major CENRAP basins, it is not possible to present them here. These compositions are presented in the natural gas composition section of the master data matrix spreadsheet accompanying this report.

## TASK 3b: RECOMMENDED PROJECTION METHODOLOGIES AND INPUT DATA FOR GENERATING 2018 EMISSIONS

The final task of this analysis is to present a methodology for scaling emissions from oil and gas area sources to 2018 in support of CENRAP's or individual state DEQ's generation of 2018 emissions inventories for modeling and other purposes. It should be noted that emissions projections of this type are often speculative and can rely only on what data are available from which to project emissions. Generally the most accurate emissions projections are achieved by utilizing the most localized projection data, but this is not always available and, as discussed below, is not available broadly for the CENRAP region.

Emissions projections to 2018 are generated by developing activity scaling factors to grow or decline emissions and then developing control factors to represent the impacts of federal or state regulations on these emissions sources. This can be done on a basin or state level, and generally follows Equation 34:

Equation (34) $$E_{2018,basin} = \sum_i E_{2002,i} \times GF_j \times CF_{federal,i} \times CF_{state,i} \times f_{basin-state}$$

where:

$E_{2018,basin}$ is the emissions in calendar year 2018 for the portion of a particular basin lying in a particular state [ton/yr]
$E_{2002,i}$ is the 2002 emissions in the basin from source category $i$ [ton/yr]
$GF_j$ is the growth or decline factor of activity surrogate $j$ from 2002 to 2018 (i.e. well count, gas production, etc.)
$CF_{federal,i}$ is the control factor (by pollutant) associated with a federal regulation that controls emissions from source category $i$
$CF_{state,i}$ is the control factor (by pollutant) associated with a state regulation that controls emissions from source category $i$

$f_{basin\text{-}state}$ is the portion of a basin lying in each state (i.e. fraction of land area, fraction of wells, etc.)

It should be noted that this approach relies on growing or declining pollutant emissions by activity surrogates, rather than predicting an actual number of wells or specific counts of equipment for a particular region. The latter approach is used most frequently in the western regional U.S. in the development of Environmental Impact Statements (EIS) or Regional Management Plans (RMP) for development of oil and gas leases on federal or state land. In an EIS or RMP analysis, it is expected that very detailed information would be available on the numbers and types of equipment that the applicant is expecting to utilize in the development area. However, regional analyses generally do not consider such specific detail in developing emissions projections, and this type of analysis is not considered in this work.

**Growth Factors**

The growth or decline factors in Equation 34 are typically developed for gas production, oil production, well counts and spud counts. They are the ratio of this activity in a basin in 2018 to the activity in 2002. There are four sources of documentation that were considered for identifying data needed to generate these growth factors:

- Broad regional oil and gas production outlooks from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) (EIA, 2008)
- Specific project-level growth or decline estimates from submitted, finalized EIS or RMP documents
- Other published studies on planned developments within the boundaries of the CENRAP region
- Extrapolation from historical data

Of these three sources, only the AEO was obtained and determined to provide sufficient data to generate growth or decline factors for the domain of the CENRAP region. It was determined that for all of the states with significant oil and gas production in the CENRAP region – Texas, Louisiana, Oklahoma, Arkansas, Kansas and Nebraska – neither the individual states nor the Bureau of Land Management (BLM) tracks information from EIS or RMP documents that would include oil and gas developments. On the state level this is because of the permitting requirements for oil and gas development in these states. On the federal level this may be because the mineral rights to the oil and gas reserves are not owned by the federal government, unlike the western regional U.S. where "split-leases" are very common and the BLM oversees significant oil and gas development projects. No other regionally-specific studies were identified that would provide more localized data to use in determining the growth or decline factors. Growth or decline curves generated on the basis of historical data require very detailed annual historical production and well statistics by basin, which were not available from the OGCC databases gathered as part of Task 1. It should also be noted that extrapolating historical production curves to future years can be inaccurate, as they assume continued growth or decline along historical trends. This may not be the case if significant levels of new development are occurring in specific regions.

The EIA's AEO is an economic forecasting model that uses supply-demand analysis to predict the growth or decline in gas and/or oil production for broad regional areas of the continental U.S.

for a number of future calendar years. The regions considered by the AEO are shown in Figure 5. The AEO also provides data on drilling estimates for future years in a more detailed analysis that was requested from the EIA for this project (EIA, 2008). It should be noted that the Louisiana-Mississippi Salt Basins lie in two AEO regions: the Gulf Coast and Midcontinent regions. For this analysis, the average of the growth or decline factors for all activity surrogates was used for this basin. The AEO does not project active well counts.

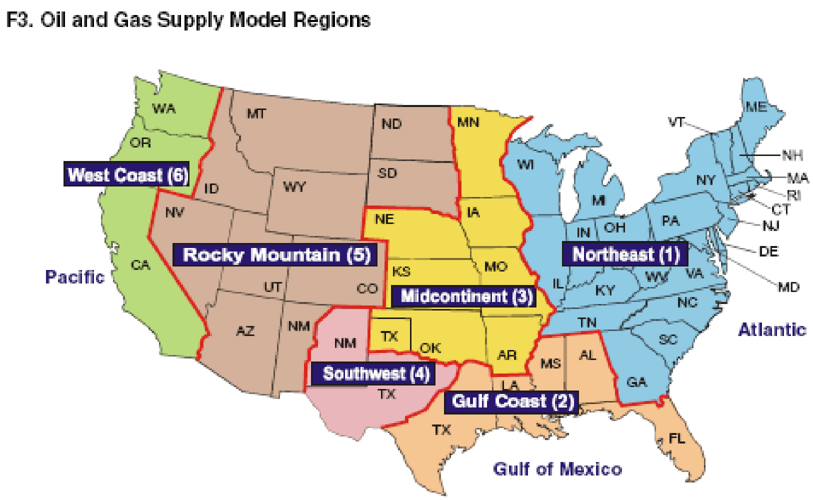


**Figure 5**. Model regions in the EIA's AEO forecasting analysis.

The growth or decline factors derived from the AEO for the three regions that lie within the CENRAP domain are presented in Table 26.

**Table 26**. AEO growth or decline factors for the three regions in the CENRAP domain.

| Activity | Study Value Growth or Decline Factor (2018/2002) | | |
|---|---|---|---|
| | EIA, 2008: Midcontinent | EIA, 2008: Southwest | EIA, 2008: Gulf Coast |
| Natural Gas Production | 0.978 | 1.094 | 0.685 |
| Crude Oil Production | 0.819 | 0.873 | 0.305 |
| Drilling | 1.265 | 0.842 | 1.596 |

These growth or decline factors must be applied to specific source categories for all of the major CENRAP basins. The specific mapping of source category to growth or decline factor is presented in Table 27 for all major oil and gas area source categories considered in this analysis. Because of the broad, regional scope of the AEO, many of the growth or decline factors are identical for specific basins and source categories.

**Table 27**. 2018 growth or decline factors by basin and source category for all major CENRAP basins.

| Source Category (Activity Surrogate) | Anadarko Basin | Arkoma Basin | Cambridge Arch Central Kansas Uplift | Cherokee Platform Basin | East Texas Basin | Fort Worth Basin | Lou |
|---|---|---|---|---|---|---|---|
| Wellhead Compressor Engines (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Lateral Compressor Engines (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Pump Jacks (Crude Oil Prod.) | 0.819 | 0.819 | 0.819 | 0.819 | 0.305 | 0.873 | |
| Drilling Rigs (Drilling) | 1.265 | 1.265 | 1.265 | 1.265 | 1.596 | 0.842 | |
| Heaters (Natural Gas Prod. and Crude Oil Prod.) | 0.898 | 0.898 | 0.898 | 0.898 | 0.495 | 0.983 | |
| Flares (Natural Gas Prod. and Crude Oil Prod.) | 0.898 | 0.898 | 0.898 | 0.898 | 0.495 | 0.983 | |
| Oil Tanks (Crude Oil Prod.) | 0.819 | 0.819 | 0.819 | 0.819 | 0.305 | 0.873 | |
| Condensate Tanks (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Completion Venting (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Dehydrators (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Blowdown Venting (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Fugitive Emissions (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |
| Pneumatic Devices (Natural Gas Prod.) | 0.978 | 0.978 | 0.978 | 0.978 | 0.685 | 1.094 | |

## Control Factors

Control factors are developed to reduce uncontrolled 2018 emissions after application of activity growth or decline factors to account for federal and/or state regulations that would affect particular oil and gas area source categories. The regulations that must be considered in the CENRAP region for generation of 2018 control factors, and the methodology by which to use these regulations to generate control factors, are presented in Table 28.

**Table 28**. Federal and state regulations applicable to various oil and gas area source categories in the CENRAP domain and recommended methodologies for developing control factors to account for these regulations.

| State | Regulations | Recommended Methodology |
|---|---|---|
| All | Federal onroad diesel engine standards (EPA, 2005b) | Use emissions standards information for 750+ hp oil field equipment diesel engines from EPA's NONROAD model to adjust drill rig engine emissions for future performance standards. This is done by running NONROAD for all relevant counties for this equipment/technology type in 2002 and then again in 2018. The ratio of fleet average per-equipment emissions in 2018 to 2002 is the control factor. |
| All | Federal mandates for non-road diesel fuel sulfur content (EPA, 2006) | Use NONROAD modeling inputs for 2002 base year inventories and EPA-mandated off-road diesel fuel sulfur levels for the 2018 calendar year to develop control factors by county for $SO_2$ emissions from drill rigs. |
| All | Federal New Source Performance Standards (NSPS) for stationary spark-ignited natural gas engines (EPA, 2008) | Develop control factor that is the ratio of NSPS-compliant wellhead and lateral compressor engine and pumpjack engine emissions factor to baseline 2002 emissions factor. Use NONROAD model to determine fraction of baseline compressor and pumpjack engines that are turned over from 2002 to 2018, and multiply control factor and turnover fraction to develop overall control factor. |
| Texas | TCEQ regulation Chapter 115, Subchapter B – Control of VOC emissions from oil/condensate tank batteries (TCEQ, 2008) | Use a 90% control factor (representing the use of vapor recovery units) for all oil and/or condensate tanks located in: Hardin, Jefferson, Orange, Collin, Dallas, Denton, Tarrant, El Paso, Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery and Waller Counties. These counties represent the Beaumont/Port Arthur, DFW, El Paso, and HGB areas covered by this regulation. |
| Texas | TCEQ regulation Chapter 117, Subchapter B Divisions 1-4 – Control of NOx emissions from major stationary sources (TCEQ, 2008) | It is assumed that this regulation applies to lateral compressor engines only, as they are the only source category that would fall under the definition of a "major source". Develop a control factor that is the ratio of the NOx emissions standard for engines covered in this definition (2.0 g/bhp-hr for rich-burn engines in all areas, 3.0 g/bhp-hr for rich-burn in Beaumont/Port Arthur non-attainment area only) to the NOx emissions factor of these engines in the base year inventory. Apply this control factor to the rich-burn engines only using the fractions presented under Task 3a (and for lean-burn engines in the Beaumont/Port Arthur non-attainment area only). This regulation applies to the Beaumont/Port Arthur nonattainment area, the Dallas-Ft. Worth nonattainment area, and the Houston-Galveston-Brazoria nonattainment area. |
| Texas | TCEQ regulation Chapter 117, Subchapter D Divisions 1-2 – Control of NOx emissions from minor stationary sources (TCEQ, 2008) | For heaters develop a control factor that is the ratio of the NOx emissions standard for heaters in this regulation to the NOx emissions of heaters in the baseline 2002 inventory (baseline heater emissions factors estimated as $EF_{NOx}/HV_{gas}$). Apply this control factor to all heater emissions in the Dallas-Ft.Worth and Houston-Galveston-Brazoria nonattainment areas. |
| | | For wellhead compressor engines develop a control factor which is the ratio of the NOx emissions standard for engines covered in this definition (0.5 g/bhp-hr for all engines in the Houston-Galveston-Brazoria nonattainment area, 0.5 g/bhp-hr for rich-burn engines in the |

| State | Regulations | Recommended Methodology |
|---|---|---|
| | | Dallas-Ft. Worth non-attainment area only and 0.7 g/bhp-hr for lean-burn engines in the Dallas-Ft. Worth non-attainment area only) to the NOx emissions factor of these engines in the base year inventory. Apply the control factor separately to the rich-burn and lean-burn engines only using the fractions presented under Task 3a for the Dallas-Ft. Worth nonattainment area. Apply this control factor to all engines for the Houston-Galveston-Brazoria nonattainment area. |
| Texas | TCEQ regulation Chapter 117, Subchapter E Division 4 – Control of NOx emissions from stationary combustion sources in East Texas (TCEQ, 2008) | It is assumed that this regulation applies to lateral compressor engines only, as they are the only source category which would fall under the definition of sources in this regulation (engine horsepower greater than 240 hp). Develop a control factor which is the ratio of the NOx emissions standard for engines covered in this definition (0.5 g/bhp-hr for rich-burn engines greater than 500 hp) to the NOx emissions factor of these engines in the base year inventory. Apply this control factor to the rich-burn engines only using the fractions presented under Task 3a. This regulation applies to the following counties in East Texas: Anderson, Brazos, Burleson, Camp, Cass, Cherokee, Franklin, Freestone, Gregg, Grimes, Harrison, Henderson, Hill, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Titus, Upshur, Van Zandt, and Wood Counties. |

Contacts at the Oklahoma DEQ indicated no specific regulations in the State of Oklahoma that would affect oil and gas area source categories (Warden, 2008). Similarly, the State of Arkansas, State of Kansas and State of Nebraska have no regulations that would impact area source categories, only major point source categories. The State of Louisiana has regulations affecting emissions from oil and gas sources as part of the Title 33 Environmental Quality Regulations, Part III (LADEQ, 2008). However, with the exception of glycol dehydrators, these regulations affect only major sources. Glycol dehydrators are required to install controls if they emit greater than 9 tpy VOC. Based on the data available for the Louisiana basins summarized in Task 3a above, dehydrator still vents will not emit more than 9 tpy and therefore this regulation is not considered applicable to these area source dehydrators. It should be noted that if in the future more detailed data on dehydrators operating in the Louisiana-Mississippi Salt Basins or Western Gulf Basin (the portion in Louisiana) is made available to CENRAP, still vent VOC emissions from these dehydrators should be reevaluated to determine if the Louisiana regulation would apply.

Finally it should be noted that control factors should also incorporate a "rule effectiveness" or "penetration rate" factor. This is usually done multiplicatively – the control factor is multiplied by the rule effectiveness and penetration rate factor to determine the overall control factor. Rule effectiveness accounts for such things as phase-in schedules of regulations, delays in implementation of technology and enforcement/compliance issues. Penetration rates refer to the fractions of fleets that comply with regulations that require some kind of phase-in, or the fractions of fleets that implement particular technologies when a regulation is performance-based (rather than technology based). These factors are typically developed by each state's DEQ or other regulatory agency. This work does not present any information on these factors, and in their absence it is assumed either that the factors are 1 or that individual state DEQ's will use their information on rule effectiveness and penetration rates in developing these control factors.

## CONCLUSIONS

A detailed set of data has been developed to aid CENRAP and each individual CENRAP state DEQ in generating improved emissions inventory calculations for oil and gas area sources within the CENRAP domain. This work has been presented in three tasks: (1) development of oil and gas production statistics; (2) a literature review and survey effort; (3) detailed methodologies and input data recommended for estimating emissions from major oil and gas source categories by basin.

From Task 1 of this work, analysis results of detailed oil and gas production statistics, organized by basin – the basic geographic unit recommended by ENVIRON for conducting oil and gas emissions inventory calculations across a broad region have been provided. These data have some limitations based on the availability of data from each state's respective OGCC or equivalent, and more accurate assessments of these statistics could be made if more detailed well-level production data were available for each state.

The Task 2 work was to evaluate data obtained from a literature review and limited survey of major oil and gas companies. The literature review focused on those major studies recommended by CENRAP and some additional studies of which ENVIRON is aware that present data useful for calculating emissions from specific source categories. A limited industry survey effort was undertaken to supplement the literature review data with operator survey data that are specific to companies' operations in various basins across the CENRAP domain.

In Task 3a of this work, the recommended methodology for estimating emissions from major oil and gas source categories was determined, and a synthesis of the input data that would be used for these calculations by basin was provided. In addition, a methodology similar to that used in the WRAP regional oil and gas emissions inventories has been presented to project emissions to the future year of 2018 in Task 3b. This methodology also considers state-specific regulations and their effects on emissions from specific source categories.

This work provides CENRAP and state DEQs with updated emissions factor and input data that can be used to estimate improved regional oil and gas area source emissions. However, it should be noted that these calculation methodologies and input data are intended for broad, regional inventories of oil and gas and therefore contain some broad assumptions to make these regional emissions inventory calculations tractable. While most major oil and gas source categories are represented here, detailed inventories of oil and gas may include other source categories and use more local data, if available.

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# APPENDIX A

## Detailed Oil and Gas Production Statistics for All CENRAP Basins

**(See attached MS Excel spreadsheet)**

# APPENDIX B

## Survey Questionnaire for Oil and Gas Companies

# CENRAP OIL AND GAS EMISSION SURVEY

**ENVIRON International Corporation**
773 San Marin Drive, Suite 2115
Novato, CA 94998

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**May 29, 2008**

ENVIRON Corporation has contracted with the Central Regional Air Partnership (CENRAP) to assist in improving the methodology for developing oil and gas air emissions inventories in member states and tribal areas including Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. This methodology will be used to develop improved emissions inventories for planning purposes including future regional haze implementation plans as well as the 2008 National Emissions Inventory (NEI) and the initial five-year regional haze State Implementation Plan (SIP) review.

ENVIRON has conducted similar methodologies for other areas in the Western Regional Air Partnership (WRAP). Our work has included estimates of air emissions from a number of processes and equipment types that stretch from the wellhead to fuel distribution networks. Our work has included the quantification of nitrous oxides (NOx), volatile organic compounds (VOC), Particulate Matter ($PM_{10}$), Carbon Monoxide (CO), Sulfur Oxides (SOx) and other pollutants from oil and gas operations. While the largest CENRAP 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 are a major priority for this study are geographically distributed and are considered area sources.

ENVIRON's experience with the WRAP regional inventories, and particularly the current Phase III inventory, is that the best emissions inventory is derived with active participation with and in cooperation with the major oil and gas producers. Therefore, we have developed a questionnaire to assist in gathering information about equipment, activity, and emissions in the major CENRAP regions of interest. Specifically, the purpose of this questionnaire is to assist in improving CENRAP's 2002 and 2018 oil and gas emissions inventories. This document contains a detailed list of questions to producers – by emissions category – that will aid in improving these emissions inventories.

**Overview**

While there are numerous operations and emissions of several pollutants, we have focused this survey on major NOx and VOC source categories. These categories are 1) drilling rigs; compressor engines; artificial lift engines (pumpjacks); dehydrators; and heaters (NOx and VOC emissions) and 2) completion activities, tank venting and flashing; blowdowns; fugitives; and pneumatic devices (VOC emissions).

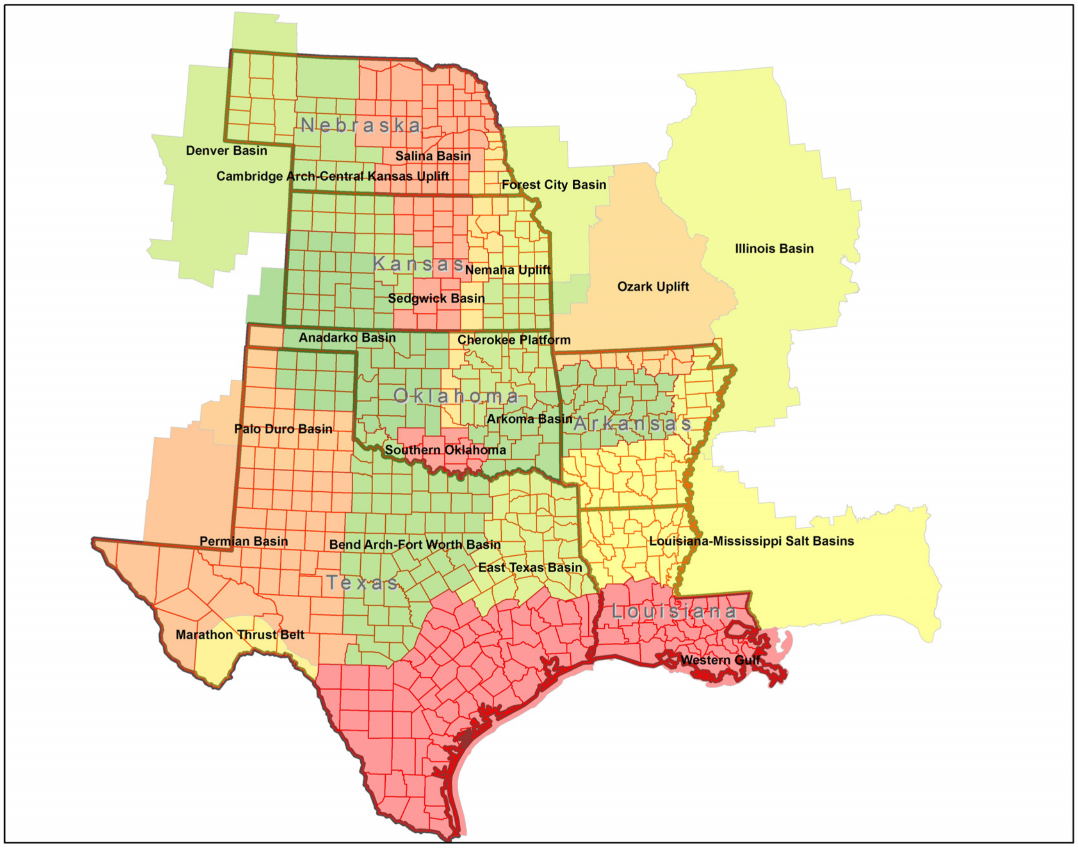
This questionnaire is organized into two sections:

1. Section 1 contains a brief checklist for producers to indicate first, whether or not you have operations identified on the checklist and second, whether the information contained in Section (2) is available. Section 1 can also be used as a quick reference guide for the information that we are requesting.

2. Section 2 contains the detailed questions for producers by emissions category

Where possible, detailed information is requested and it is preferable that this information be provided in electronic form. In order to meet our schedule for completing the task, the deadlines for receiving information is by **June 30, 2008**.

The figure below shows, in graphical form, the CENRAP states and basins for which data is being requested.




The states and basins of interest are as listed below:

**Nebraska**
- Cambridge Arch-Central Kansas Uplift
- Denver Basin
- Forest City Basin
- Salina Basin

**Kansas**
- Anadarko Basin
- Cambridge Arch-Central Kansas Uplift
- Cherokee Platform
- Forest City Basin
- Nemaha Uplift
- Salina Basin
- Sedgwick Basin

**Oklahoma**
- Anadarko Basin
- Arkoma Basin
- Bend Arch-Fort Worth Basin
- Cherokee Platform
- Nemaha Uplift
- Ozark Uplift
- Southern Oklahoma

**Arkansas**
- Arkoma Basin
- Illinois Basin
- Louisiana-Mississippi Salt Basins
- Ozark Uplift

**Texas**
- Anadarko Basin
- Bend Arch-Fort Worth Basin
- East Texas Basin
- Marathon Thrust Belt
- Palo Duro Basin
- Permian Basin
- Western Gulf

**Louisiana**
- Louisiana-Mississippi Salt Basins
- Western Gulf

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 **June 10, 2008** about whether or not the information on the specific questions included in this questionnaire will be made available, and for which basins this information is available (in which basins your company operates). Please use the checklist in Section 1 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 that 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 basin only. ENVIRON will sign a confidentiality agreement with your company if that will be necessary for you to provide the information requested. 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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773 San Marin Drive, Suite 2115
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Email: abarilan@environcorp.com

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.

**CENRAP OIL AND GAS**
**EMISSION SURVEY**

**SECTION 1**

**Checklist**

**ENVIRON International Corporation**
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Contact:
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**May 29, 2008**

Below is a brief checklist of the information requested in this questionnaire. Please indicate whether or not you operate this equipment and whether information on each emissions category is available **for each basin in which you operate,** 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, June 10, 2008.**

All of the detailed responses to questions and any quantitative data should be forwarded to ENVIRON by the June 30, 2008 deadline.

**Table I.** Drilling Rig Emissions.

| | **Do you operate this equipment? (Y/N)** | **Do you have information on this equipment for calendar year 2002? (Y/N)** | **If information is unavailable for 2002, for which year is it available?** |
|---|---|---|---|
| Drilling times | | | |
| Drilling depths | | | |
| Typical rig configuration | | | |
| Fuel type | | | |
| Fuel consumption rate | | | |

**Table II.** Compressor Engine Emissions.

| | **Do you operate this equipment? (Y/N)** | **Do you have information on this equipment for calendar year 2002? (Y/N)** | **If information is unavailable for 2002, for which year is it available?** |
|---|---|---|---|
| Fraction of wells with wellhead/lateral compressor engines | | | |
| Number of central compressor stations by basin | | | |
| Average horsepower of a wellhead/lateral/central compressor | | | |
| Average load on compressors by basin | | | |
| Average makes/models of compressors by basin | | | |
| Information about controls on compressors and rich-burn vs. lean-burn compressors | | | |
| Emissions data from central compressor station permits | | | |

**Table III.** Artificial Lift Engines.

| | Do you operate this equipment? (Y/N) | Do you have information on this equipment for calendar year 2002? (Y/N) | If information is unavailable for 2002, for which year is it available? |
|---|---|---|---|
| Fraction of oil wells with artificial lift engines | | | |
| Average horse power of artificial lift engines | | | |
| Average makes/models of artificial | | | |
| Artificial lift engine fuel | | | |
| Controls used on artificial lift engines | | | |

**Table IV.** Heaters.

| | Do you operate this equipment? (Y/N) | Do you have information on this equipment for calendar year 2002? (Y/N) | If information is unavailable for 2002, for which year is it available? |
|---|---|---|---|
| Number of heaters for a typical well setup | | | |
| Average heater rating | | | |
| Average annual usage | | | |

**Table V.** Natural Gas Composition Analysis.

| | Do you have natural gas composition analyses (Y/N) |
|---|---|
| Natural gas composition analysis lab report | |
| $H_2S$ data available | |

**Table VI .** Oil and Condensate Tank Emissions.

| | Do you operate this equipment? (Y/N) | Do you have information on this equipment for calendar year 2002? (Y/N) | If information is unavailable for 2002, for which year is it available? |
|---|---|---|---|
| Emission factors of lb VOC/barrel of oil/condensate produced for oil and condensate tanks | | | |
| Fractions of total production transported via pipeline | | | |
| Fraction of total production routed to flares | | | |

**Table VII.** Fugitives Emissions.

| | Do you operate this equipment? (Y/N) | Do you have information on this equipment for calendar year 2002? (Y/N) | If information is unavailable for 2002, for which year is it available? |
|---|---|---|---|
| Typical oil, gas and CBM well setup | | | |
| Number and type of components | | | |

**Table VIII.** Pneumatic Devices.

| | Do you operate this equipment? (Y/N) | Do you have information on this equipment for calendar year 2002? (Y/N) | If information is unavailable for 2002, for which year is it available? |
|---|---|---|---|
| Number and type of devices used at typical well setup | | | |
| Information on instrument air or low-bleed devices in use | | | |

**Table IX.** Venting Emissions.

| | Do you have this equipment or conduct these operations? (Y/N) | Do you have information on this equipment or these operations for calendar year 2002? (Y/N) | If information is unavailable for 2002, for which year is it available? |
|---|---|---|---|
| Frequency of venting at wells (blowdowns) | | | |
| Venting volume per event (blowdowns, completions) | | | |
| Control measures or best practices implemented (blowdowns, completions) | | | |
| Glycol dehydrator usage | | | |
| Glycol dehydrator emissions rates | | | |

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# CENRAP OIL AND GAS
# EMISSION SURVEY

## SECTION 2

## Detailed Questions

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**May 29, 2008**

**GENERAL QUESTIONS/COMMENTS**

1. Please provide an overview of your oil and gas operations in the CENRAP region; including
   - Basins in which you operate
   - Basins in which you have production operations
   - Primary product(s) in each basin: oil, gas, CBM gas, sour gas, etc.
   - Primary focus of operation: exploration and production or midstream
2. In responding to the questions below, please indicate the following for all information that you provide to us:
   - Basin to which your information refers
   - Whether the basin has conventional or CBM production or both
   - Whether the basin has significant sour gas ($H_2S$) production.
3. Please respond to all questions with information from calendar year 2002.

## A. <u>MAJOR NOx EMITTER SOURCE CATEGORIES</u>

### I. DRILLING RIG EMISSIONS

1. What are the average drilling times (from beginning to completion of drilling) for your drilling operations by basin in all basins in which you operate in the CENRAP states?
2. What are the average drilling depths for your drilling operations by basin?
3. Please describe a typical configuration of a drilling rig – the number and type of each engine (draw works, mud pump, generator), horsepower, load factor, percentage of time the engine is in operation during a drilling event, and makes/models of the engines if possible. Please provide this information by basin for each of the basins in which you operate.
4. What type of diesel fuel was used in 2002 and what was the sulfur content of that diesel fuel for your drilling operations in each basin?
5. Please provide, if possible, information on the total fuel consumption, or fuel consumption rate of drilling rig engines that you operate in each basin.

### II. COMPRESSOR ENGINE EMISSIONS

1. This is a two-part question:
   - What fraction of the number of wells in each basin in which you operate use wellhead compressors? What is a typical make/model of wellhead compressor? What is a typical horsepower of a wellhead compressor? What is the load factor on a typical wellhead compressor? Are there controls in place on your wellhead compressors? What types of controls and on what fraction of the compressors? What fraction of these compressors are rich-burn, and what fraction are lean-burn?
   - What fraction of the number of wells in each basin in which you operate use lateral compressors? What is a typical make/model of a lateral compressor? What is a typical horsepower of a lateral compressor? What is the load factor on a typical lateral compressor? Are there controls in place on your lateral compressors? What types and on what fraction of the compressors?

2. Can you provide information from permits on your permitted central compressor stations? Please provide information on the number of central compressor stations you operate in each basin, and typical emissions (tons per year) of NOx, CO, VOC, PM, SOx from these compressor stations.

### III. ARTIFICIAL LIFT ENGINES (PUMPJACKS):

1. What fraction of oil wells use artificial lift engines – please reply for each basin in which you operate?
2. What is the average horsepower of artificial lift engines used in your operations in each basin?
3. What is a typical make and model of artificial lift engine in each basin in which you operate?
4. What type of fuel is used for artificial lift engines? What is the sulfur content of the fuel?
5. What controls, if any, are used for artificial lift engines? What fractions of these engines are electrified? Please reply for each basin in which you operate.

### IV. HEATERS:

1. Please provide the number of heaters at a **typical well setup** for oil, conventional gas and CBM gas wells in each basin in which you operate.
2. What is the average heater rating (MMBtu/hour) of the heaters used for your operations in each basin?
3. What is the average annual usage per heater for your operations in each basin (hours/year)?

## B. MAJOR VOC EMITTER SOURCE CATEGORIES

### V. NATURAL GAS COMPOSITION ANALYSIS

Natural gas composition is needed to estimate VOC emissions from such sources as pneumatic devices, fugitive emissions, well blowdowns, and completions.

1. Please provide a sample natural gas composition analysis for a typical well in each basin in which you operate. Please indicate whether this analysis is from a coal bed methane or conventional well.
2. Please ensure that any gas composition analysis provided indicates the presence or absence of $H_2S$ in the gas and the $H_2S$ fraction if present

### VI. OIL AND CONDENSATE TANK EMISSIONS

Flashing, working and breathing losses are significant contributors to VOC emissions. To develop emissions from oil or condensate tank please provide the requested information below.

1. Have you ever developed flashing, working, and breathing loss emission factors of lb-VOC/barrel of condensate produced using EPA Tank4 model for the oil and condensate tanks for each basin in which you operate? If so, please provide emission factors of lb-VOC/barrel of condensate produced for oil and condensate tanks.
2. What fraction of the total production is directly transmitted to pipelines rather than being stored in tanks?

3. What fraction of production is stored in tanks which are equipped with flares to control flash gas emissions?

## VII. FUGITIVE EMISSIONS

Fugitive emissions are due to leakage in the equipment in a processing unit. Please provide information on Typical Well configuration for fugitive emissions.

1. Please provide a **typical well setup** for oil, conventional gas and CBM gas wells in which the type, service, and number of components per well type are specified for each basin in which you operate.
    - Typical components which could have fugitive emissions are: valves, pump seals, connectors, flanges, open-ended lines, or other devices (please specify)
    - For a typical well component count, please indicate if the device is for gas, water/oil, light oil, or heavy oil service

## VIII. PNEUMATIC DEVICES

1. Please provide a **typical well setup** for oil, conventional gas and CBM gas wells in which the type and number of pneumatic devices per well type are specified for each basin in which you operate.
    - Typical pneumatic devices are: liquid level controllers, pressure controllers, positioners, transducers
    - Please indicate what fraction of your high-bleed pneumatic devices run on instrument air, or have been replaced by low-bleed devices

## IX. VENTING EMISSIONS

1. How frequently do you conduct well blowdowns per well, and what is the vented volume and the duration of venting for a typical blowdown for each basin in which you operate?
2. What is the typical vented volume during a well completion, and what is the duration of this venting for each basin in which you operate?
3. Please quantify any control measures or best practices you have implemented to reduce blowdown or completion venting emissions for each basin in which you operate.
4. For each basin in which you operate, please indicate whether you use glycol dehydrators in the field or 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.
    - Are controls used on the dehydrators? If so, what types of controls are used (flaring or closed vents) and on what fraction of the dehydrators?

# APPENDIX C

## Master Data Matrix of Input Data for Emissions Inventory Calculations for All CENRAP Basins

**(See attached MS Excel Spreadsheet)**