ATTACHMENT H

DEVELOPMENT OF TEXAS STATEWIDE DRILLING RIGS EMISSIONS INVENTORIES FOR THE YEARS 1990, 1993, 1996, AND 1999 THROUGH 2040

DEVELOPMENT OF TEXAS STATEWIDE DRILLING RIGS EMISSIONS INVENTORIES FOR THE YEARS 1990, 1993, 1996, AND 1999 THROUGH 2040

This attachment provides the detailed documentation of methods and procedures used to develop statewide controlled and uncontrolled emissions inventories for drilling rig engines associated with Texas onshore oil and gas exploration activities.

Eastern Research Group, Inc.

DEVELOPMENT OF TEXAS STATEWIDE DRILLING RIGS EMISSION INVENTORIES FOR THE YEARS 1990, 1993, 1996, AND 1999 THROUGH 2040

FINAL REPORT

TCEQ Contract No. 582-11-99776
Work Order No. 582-11-99776-FY11-05

Prepared for:

Texas Commission on Environmental Quality
Air Quality Division

Prepared by:

Eastern Research Group, Inc.

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LIST OF ACRONYMS

Acronym	Definition
API	American Petroleum Institute
CERR	Consolidated Emissions Reporting System
CO	Carbon Monoxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERG	Eastern Research Group
HAP	Hazardous Air Pollutant
hp	Horsepower
MMBBL	Million Barrels
NIF	NEI Input Format
NO_x	Nitrogen Oxides
OSD	Ozone Season Daily
PM_{10}	PM with particle diameter less than 10 micrometers
$PM_{2.5}$	PM with particle diameter less than 2.5 micrometers
QAPP	Quality Assurance Project Plan
SCC	Source Classification Code
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TCEQ	Texas Commission on Environmental Quality
TexAER	Texas Air Emissions Repository
TOG	Total Organic Gases
TRC	Texas Railroad Commission
TxLED	Texas Low Emission Diesel
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
XML	Extensible Markup Language

1. Executive Summary

The purpose of this study was to develop comprehensive statewide controlled and uncontrolled emissions inventories for drilling rig engines associated with onshore oil and gas exploration activities occurring in Texas. Oil and gas exploration and production facilities are considered some of the largest sources of area source emissions in certain geographical areas, dictating the need for continuing studies and surveys to more accurately depict these activities. The current inventory effort builds off of the previous 2009 study prepared for the TCEQ, 2009 Drilling Rig Emission Inventory for the State of Texas (July 15, 2009, prepared by ERG), which focused exclusively on drilling activities. The previous effort is expanded upon by improving the activity data (well counts, types, and depths) used to estimate emissions, and uses the drilling rig engine emission profiles developed in the 2009 study. The improved well activity data was obtained through acquisition of the "Drilling Permit Master and Trailer" database from the Texas Railroad Commission (TRC). The activity data and emissions characterization data were then used to develop controlled and uncontrolled drilling rig engine emissions inventories for the years 1990, 1993, 1996, and 1999 through 2040.

The rig profiles developed in the 2009 study provided:

- The average number of engines on a rig
- Average engine model year and size (hp)
- Average load for each engine
- Engine function (draw works, mud pumps, power)
- Average engine hour data for each well (total hours)
- Average well drilling time (actual number of drilling days)
- Average well completion time (number of days needed for well completion activities)
- Average well depth

Target pollutants for this study include nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), and hazardous air pollutants (HAP). Emissions were calculated for each county in Texas where drilling occurred and are provided in annual tons per year and by typical ozone season day. Emission estimates for years prior to 2011 were based on TRC records of oil and gas well completions during those years, and U.S Department of Energy (DOE), Energy Information Administration (EIA) oil and gas production growth estimates were used to develop the projections for the years 2011 forward.

Emissions estimates developed from this inventory project may be used for improved input data to photochemical air quality dispersion modeling, emissions sensitivity analyses, State Implementation Plan (SIP) development, and other agency activities.

The final inventory estimates are provided in Consolidated Emissions Reporting System (CERS) Extensible Markup Language (XML) to facilitate entry of the data into the state's TexAER (Texas Air Emissions Repository) database, and for the purposes of submittal to US EPA. For purposes of XML preparation, Source Classification Code (SCC) 23-10-000-220 (Industrial Processes - Oil and Gas Exploration and Production - All Processes - Drill Rigs) was used, consistent with the 2009 study.

Table 1-1 summarizes the statewide annual emission estimates for 1990, 1993, 1996, and 1999 through 2040. Figures 1-1 through 1-3 present this same information in chart form. Note that the PM_{10} and $PM_{2.5}$ values are so close together that they are difficult to distinguish in Figure 1-3. Appendix A provides the corresponding statewide emissions estimates for HAPs.

Table 1-1. Statewide Drilling Rig Estimates (Tons/Year)

Year	CO	NO_X	$PM_{2.5}$	PM_{10}	SO_2	VOC
1990	13,366	25,308	2,457	2,533	3,037	3,462
1993	15,193	29,354	2,743	2,828	3,141	3,940
1996	15,502	33,037	2,737	2,822	4,093	4,044
1999	10,568	24,159	1,707	1,760	1,647	2,769
2000	14,570	33,578	2,350	2,422	2,290	3,798
2001	16,910	38,960	2,726	2,810	2,641	4,410
2002	11,027	27,974	1,919	1,978	2,100	2,955
2003	14,234	37,220	2,471	2,548	2,825	3,803
2004	15,057	40,164	2,607	2,688	3,040	4,047
2005	17,706	47,798	3,068	3,163	3,606	4,788
2006	15,235	52,497	2,463	2,539	4,290	4,135
2007	16,071	57,197	2,320	2,392	909	4,443
2008	17,745	59,261	2,615	2,696	1,033	4,593
2009	8,464	29,231	1,244	1,282	523	2,202
2010	7,182	24,531	1,024	1,056	21	1,846
2011	6,869	23,254	1,016	1,047	21	1,725
2012	6,949	22,920	1,028	1,060	22	1,716
2013	5,893	19,878	652	672	19	1,687
2014	5,916	19,875	655	675	20	1,691
2015	5,897	19,819	653	673	20	1,693
2016	5,826	18,711	643	663	20	1,691
2017	4,375	17,954	537	553	19	1,417
2018	3,085	16,446	400	413	19	1,164
2019	3,096	16,545	402	414	19	1,170
2020	3,102	16,475	402	415	20	1,175
2021	1,712	14,182	233	240	19	832
2022	1,705	14,201	233	240	19	837
2023	1,711	14,308	234	242	19	843
2024	2,178	16,194	308	318	22	956

Year	CO	NO_X	$PM_{2.5}$	PM_{10}	SO_2	VOC
2025	2,170	16,186	307	317	22	956
2026	2,409	18,006	346	357	24	1,032
2027	1,307	11,359	221	228	19	732
2028	1,269	11,190	219	226	19	725
2029	1,254	9,817	185	190	18	787
2030	1,244	9,762	183	189	18	783
2031	1,233	8,878	172	177	17	778
2032	1,200	8,649	170	175	17	772
2033	779	8,566	143	148	17	671
2034	770	8,490	142	146	17	665
2035	761	8,410	140	145	17	660
2036	387	7,869	96	99	16	637
2037	385	7,861	96	99	16	637
2038	384	7,853	96	99	16	637
2039	382	7,316	96	99	16	637
2040	381	7,311	96	99	16	637

Figure 1-1. Statewide Drilling Rig Estimates (NO_x and CO Tons/Year)

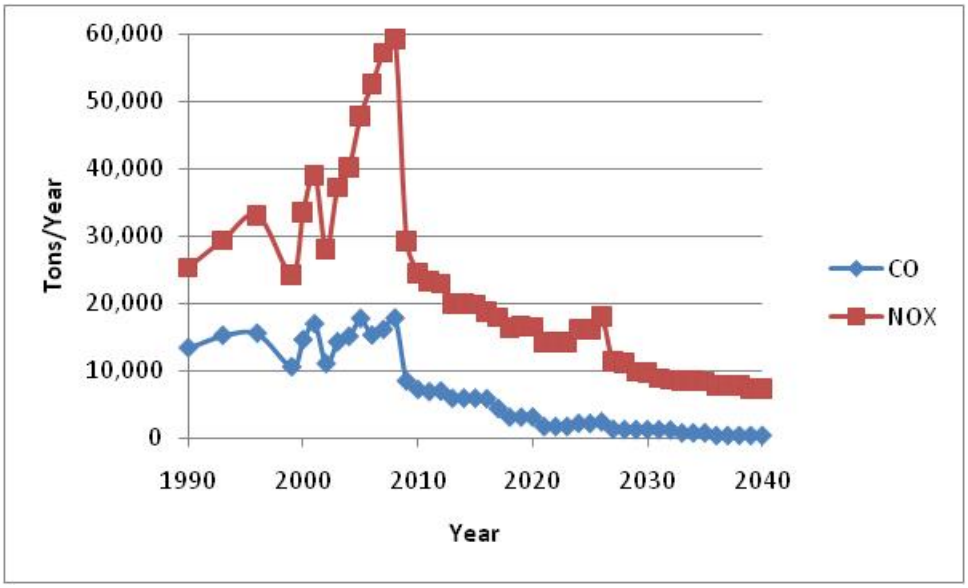


Figure 1-2. Statewide Drilling Rig Estimates (VOC and SO_2 Tons/Year)

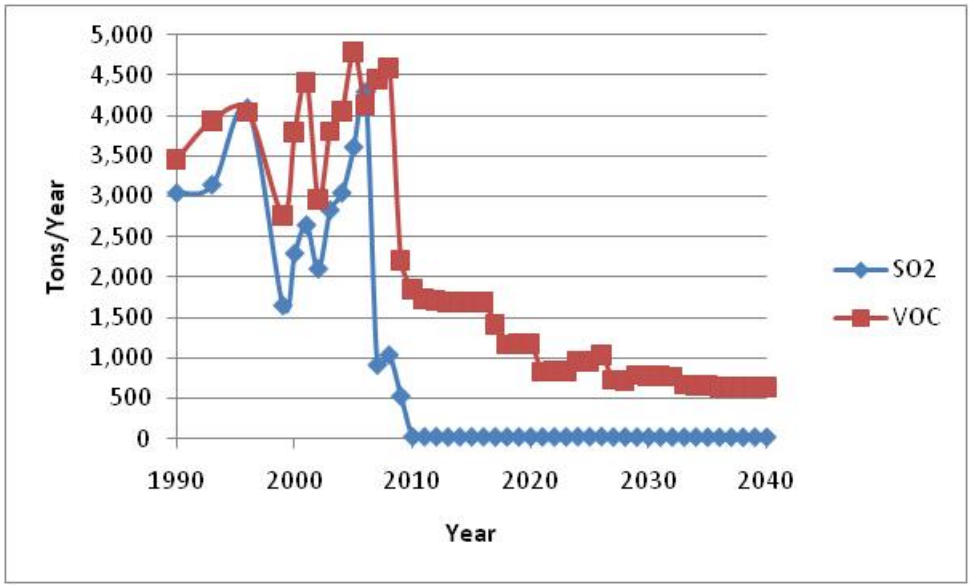
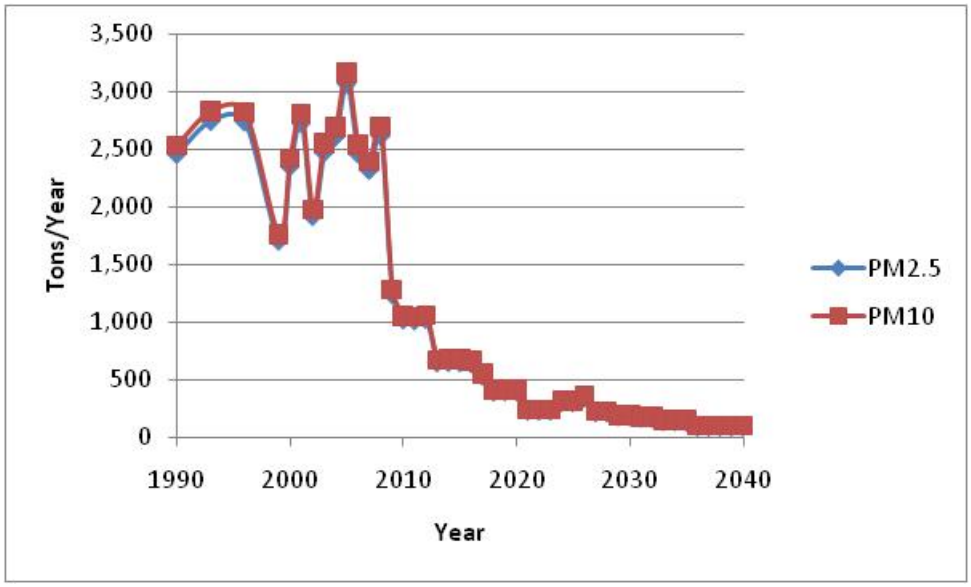


Figure 1-3. Statewide Drilling Rig Estimates (PM_{10} and $PM_{2.5}$ Tons/Year)



The study results provide a significant improvement upon the 2009 effort, utilizing improved gap filling methods for the TRC dataset to obtain a more complete and accurate set of drill rig activity. In addition, this study utilized historical drilling data from the TRC to estimate past emissions, rather than relying on surrogate based back-casting from a base year, as was done in the previous study. Finally, the study greatly expanded the time horizon of the previous study, ranging from 1990 with projections through 2040. The result is a reliable, temporally resolved profile of county-level drilling activity emissions. The successful update of the state's TexAER database system

with this data, associated with a new area source SCC, will allow for improved SIP and trend analysis for all regions of the state.

Based on the projected oil and gas production levels in Texas from the EIA, drilling activity is estimated to remain relatively constant across the state from 2011 through 2035. However, the continued phase-in of more stringent Non-Road diesel engine emission standards should cause a steady decrease in drilling-related emissions over time. SO_2 emissions levels in particular are estimated to have fallen precipitously due to the introduction of the ultra-low sulfur standards for diesel fuel in 2010, and should remain extremely low for the foreseeable future.

An analysis of county-level data found that the vast majority of Texas counties produced some level of emissions associated with drilling activities (206 of 254 counties) in the 2010 base year. However, the county-level distribution of NO_x emissions is highly skewed, with 14 counties being responsible for 50 percent of total statewide NO_x in 2010. In addition, the preponderance of the high NO_x emitting counties were predominantly in West and North-Central Texas.

While the emissions inventory results provide an excellent basis for assessing historical emissions levels, significant sources of uncertainty remain. Most importantly, projections of future activity are highly uncertain, subject to significant rises and falls depending upon economic factors and associated oil and gas prices. Accordingly, periodic refinement of the activity data used for projected years 2011 through 2040 is strongly recommended to account for such factors. In addition, the contribution of hydraulic fracturing operations to drilling activity emissions remains unknown at this time.

2. Introduction

The purpose of this study was to develop comprehensive statewide controlled and uncontrolled emissions inventories for drilling rig engines associated with onshore oil and gas exploration activities occurring in Texas. Oil and gas exploration and production facilities are considered some of the largest sources of area source emissions in certain geographical areas, dictating the need for continuing studies and surveys to more accurately depict these activities. The current inventory effort builds off of the previous 2009 study prepared for the TCEQ, 2009 Drilling Rig Emission Inventory for the State of Texas (July 15, 2009, prepared by ERG), which focused exclusively on drilling activities. The previous effort is expanded upon by improving the activity data (well counts, types, and depths) used to estimate emissions, and uses the drilling rig engine emission profiles developed in the 2009 study. The improved well activity data was obtained through acquisition of the "Drilling Permit Master and Trailer" database from the Texas Railroad Commission (TRC). The activity data and emissions characterization data were then used to develop controlled and uncontrolled drilling rig engine emissions inventories for the years 1990, 1993, 1996, and 1999 through 2040.

While drilling activities are generally short-term in duration, typically covering a few weeks to a few months, the associated diesel engines are usually very large, from several hundred to over a thousand horsepower (hp). As such, drilling activities can generate substantial amounts of NO_x emissions. While previous studies have focused more intently on quantifying the ongoing fugitive VOC emissions associated with oil and gas production, significant uncertainty remains regarding the shorter term NO_x emission levels associated with drilling activity.

The activity and drilling rig engine emissions profiles developed under the 2009 study were used to develop emissions estimates of VOC, NO_x, CO, PM_{10} and $PM_{2.5}$, SO_2, and HAP for drilling rig engines across the state. Emissions are calculated on a county-level basis and provided in annual tons per year and by typical ozone season day.

Section 3.0 of this report provides an overview of the drilling process and identifies the types of activities and equipment that are commonly associated with drilling activity. Section 4.0 describes the development of the emissions inventory including how the activity data was compiled, how the model drilling rig emission profiles were developed, and how these model drilling rig emission profiles were combined with the activity data to develop the emission inventories, along with quality assurance measures applied. Section 5.0 summarizes the conclusions for this study and offers recommendations for future studies.

3. Drilling Rig Overview

3.1 Drilling Permits

All exploratory oil and gas drilling in Texas requires a permit. These permits are processed and maintained through the TRC. The drilling permits are available for review through the TRC website, and include well-specific data such as approval date, location (county), well profile (vertical, horizontal, directional), well depth, start or "spud-in" date, and well completion date. ERG obtained this data in electronic format through acquisition of the "Drilling Permit Master and Trailer" database. This database formed the basis of the activity data used to develop the historical emissions inventories (those prior to 2011).

3.2 Drilling Rig Overview

Air pollutant emissions from oil and gas drilling operations originate from the combustion of diesel fuel in the drilling rig engines. The main functions of the engines on an oil and gas drilling rig are to provide power for hoisting pipe, circulating drilling fluid, and rotating the drill pipe. Of these operations, hoisting and drilling fluid circulation require the most power.

There are two common types of rigs currently in use – mechanical and electrical. In general, mechanical rigs have three independent sets of engines. The first set of engines (draw works engines) are used to provide power to the hoisting and rotating equipment, a second set of engines (mud pump engines) are dedicated to circulating the drilling fluid which is commonly referred to as "mud", and a third set of engines (generator engines) are used to provide power to auxiliary equipment found on the drill site such as lighting equipment and heating and air conditioning for crew quarters and office space. There may be one, two, or more draw works engines, depending on the input power required. There are typically two mud pumps for land rigs, with each mud pump independently powered by a separate engine. The mud pump engines are typically the largest engines used on a mechanical rig. Finally, there are typically two electric generator engines per mechanical rig, with one running continuously and the second serving as a stand by unit.

Electrical rigs are typically comprised of two to three large, identical diesel-fired engine-generator sets that provide electricity to a control house called a silicon controlled rectifier (SCR) house. Electricity from the SCR house is then used to provide power to separate motors on the rig. In this configuration, there are dedicated electric motors used for the draw works/hoisting operations, the mud pumps, and other ancillary power needs (such as lighting). The generator engines are loaded as required to meet fluctuating power demands, with one unit typically designated for standby capacity. The

trend in new rig design is almost exclusively towards electric rigs, except perhaps for the smallest rigs. This is probably due to the relative expense of engines versus motors, both in terms of initial cost and maintenance. Today, electrical rigs are common, especially for larger rigs (Bommer, 2008).

After drilling and casing a well, it must be "completed." Completion is the process in which the well is enabled to produce oil or gas. Once the desired well depth is reached, the geological formation must be tested and evaluated to determine whether the well will be completed for production, or plugged and abandoned. To complete the well production, casing is installed and cemented and the main drilling rig is dismantled and moved to the next site. A smaller rig, called a completion rig (also known as a workover rig), is then moved on site to bring the well into production, to perforate the production casing and run production tubing to complete the well. Typically, the completion rig is a carrier-mounted arrangement and may be on-site for several days to a week or more depending on well depth and other factors. The completion rigs hoist smaller loads and pump at lower rates than the drilling rigs, and therefore require much smaller engine capacity.

Increasingly, reservoir productivity is enhanced by the application of a stimulation technique called hydraulic fracturing.[1] Fracturing jobs are often high rate, high volume, and high pressure pumping operations. They are accomplished by bringing very large truck- mounted diesel-powered pumps (e.g., 2,000 hp or more) to the well site to inject the fracturing fluids and material, and to power the support equipment such as fluid blenders. In this process, the reservoir rock is hydraulically overloaded to the point of rock fracture. The fracture is induced to propagate away from the well bore by pumping hydraulic fracturing fluid into the well bore under high pressure. The fracture is kept open after the end of the job by the introduction of a solid proppant (sand, ceramic, bauxite, or other material), by eroding the sides of the fracture walls and creating rubble by high injection rates, or for carbonate formations, by etching the walls with acid. The fracture thus created and held open by the proppant materials becomes a high conductivity pathway to the well bore for reservoir fluid.

Fracturing generally takes place directly after removal of the completion rig in order to initiate gas production. Therefore it is reasonable to assume that most fracturing occurs within days or weeks of well completion. The frequency and timing of both fracturing as well as re-fracturing (wherein a well nearing exhaustion is fractured again in order to re-invigorate gas flow), is not contained in the TRC database and is unknown.

Oil and gas wells are commonly classified as vertical, directional, or horizontal wells, depending on the direction of the well bore. Vertical wells are the most common, and

[1] Hydraulic methods are the only type of fracturing known to occur with any frequency in the shale formations in Texas.

are wells that are drilled straight down from the location of the drill rig on the surface. Directional wells are wells where the well bore has not been drilled straight down, but has been made to deviate from the vertical. Directional wells are drilled through the use of special tools or techniques to ensure that the well bore path hits a particular subsurface target, typically located away from (as opposed to directly under) the surface location of the well. Horizontal wells are a subset of directional wells in that they are not drilled straight down, but are distinguished from directional wells in that they typically have well bores that deviate from vertical by 80 - 90 degrees. Horizontal wells are commonly drilled in shale formations. Once the desired depth has been reached (the well bore has penetrated the target formation), lateral legs are drilled to provide a greater length of well bore in the reservoir.

In vertical wells, a single fracture job per reservoir is commonly done. In high angle or horizontal wells, it is common to perform multiple fracturing jobs (multi stage fracturing) along the path of the bore hole through a reservoir. The measure of the power required is based on the hydraulic horsepower necessary to fracture the well. Although very short in duration (typically less than a day), fracturing activities may result in substantial NO_x emissions due to the very high horsepower requirements.

4. Emissions Inventory Development and Results

The activity data from the TRC and the model rig emissions profiles developed in the 2009 study for each model rig well type category were utilized to develop emissions estimates for selected target years, as described in the following sections. The 2009 study, which serves as the basis for the current inventory development, attempted to characterize activity and emissions for all significant sources associated with drilling activities. Note that small engines – e.g., 25 hp and less – were excluded from the survey effort due to their anticipated low levels of emissions. In addition, the survey results did not find any engines powered by gasoline or natural gas, so emission inventory estimates were limited to diesel engines.

EPA's NONROAD emission factor model estimates emissions for "Other Oil Field Equipment" which includes fracturing rigs, mechanical drilling engines, oil field pumps, pump jacks, and seismograph rigs (PSR 1998). Of these subcategories, only the first three are involved in drilling activities. The 2009 survey results successfully profiled activity and population levels for drilling engines and pumps, as well as electrical generators used to power auxiliary equipment as described in the previous section.

During the data collection phase of the 2009 study, information was also solicited from respondents regarding fracturing activities. As part of their survey response, drilling contractors and oil and gas exploration companies occasionally provided some qualitative or quantitative information regarding fracturing, but the responses were highly variable in content and format. In general, the indication was that fracturing was a short-term activity (less than one day in duration), and that pump trucks containing multiple, large diesel-fired engines could be used simultaneously to pump the fracturing fluids into the well.[2]

Specific information regarding the frequency of fracturing events and the total hp-hours required per event were not generalizable to the inventory as a whole, however. Further investigation regarding fracturing was made by contacting service companies that provide fracturing services, as well as interviewing personnel at the TRC and researching the availability of fracturing data on-line through the TRC website. Two of the three service companies contacted provided some data for the fracturing activities performed in 2008, which varied from the use of five 1,250 hp pump engines for a total duration of 1 hour, to the use of seven 2,500 hp pump engines for a total duration of 12 hours. The third service company contacted did not provide any data.

[2] Note that these pump engines are different than the pumps used to circulate drilling fluid, as profiled for this inventory.

Unlike the drilling permit records obtained through the "Drilling Permit Master and Trailer" database, fracturing data is not compiled by the TRC or otherwise made readily available in any summarized format through any on-line queries or electronic datasets. However, images of individual well completion records (referred to as G-1 forms for gas well completions and W-2 forms for oil well completions) are available on-line through the TRC website. Using American Petroleum Institute (API) numbers from the TRC data, a random on-line search was performed to review the G-1 and W-2 records for approximately 1,200 wells. The G-1 and W-2 forms were only found for approximately one-third of these wells. These forms are frequently completed by hand, with inconsistent data being reported by individual well operators, with much of the data being incomplete. However, based on a review of the records we were able to identify, it appears that approximately 80% of the wells in the sample had some kind of fracturing activity occurring prior to well completion. (Given the short duration of fracturing activities, it is reasonable to assume that most or all of the emissions associated with fracturing occur in the same year as the emissions associated with drilling.) While data is not currently available under this project to provide emission estimates for fracturing activities, due to the large engine sizes used by the pump trucks, this is a source category that may be considered for inclusion in future emission inventory development projects.

4.1 Activity Data

4.1.1 Historical Activity

The Texas Railroad Commission (TRC) maintains oil and natural gas drilling permits for the state of Texas. ERG obtained a copy of the database in ASCII, position-delimited format from a TRC download on May 12, 2011. Using the TRC manual, ERG uploaded the database file into Microsoft Access. The database file contained over 650,000 unique drilling permit and well ID records from 1948 to mid-2011. ERG was tasked with identifying historical drilling activities which occurred in base years 1990, 1993, 1996, and from 1999-2010 for a total of 15 years. [3] In addition to descriptive information about each permit record (i.e., permit number, American Petroleum Institute (API) number, Well ID, etc.), the TRC data file contains information for when drilling began (Spud Date), when drilling was completed (Drilling Completion Date), wellbore profile type (vertical or horizontal), and permitted well depth.

It is important to note that approximately 19% of the data records did not contain both Spud Date and Completion Date, thus it could not be determined definitively if activity occurred during a base year of interest. It is believed that these records were administrative records, and no drilling activity was associated with these entries. Additionally, over 51% of the data records had either a Spud Date in 2011, finished

[3] Note that unlike the 2009 study, which back-cast well activity levels using surrogates, this study used actual historical activity levels for all years between 1990 and 2010.

drilling prior to 1990, or the entire drilling activity took place in a non-base year of interest (1991, 1992, 1994, 1995, 1997, or 1998). As such, these records were not included in the analysis. Finally, we identified approximately 4% of the data as having either a Spud Date or a Drilling Completion Date, but not both. We "flagged" these records as possibly occurring during a base year of interest. As a result, over 168,000 data records (~ 26%) were initially identified as having drilling activities occurring during one of the 15 years of interest.

Prior to calculating the activity data needed to calculate estimated drilling emissions, ERG reviewed the flagged records to potentially add to the records of interest. We used the TRC website (www.rrc.state.tx.us) to approximate surrogate Spud or Drilling Completion Dates. Specifically, if a Spud Date was missing, ERG used the TRC Permit Approved Date as a surrogate for Spud Date and Surface Casing Date or Well Completion Date as a surrogate Drilling Completion Date. However, since there were over 25,000 flagged records, it was not feasible to examine each one due to time and resource constraints. Therefore, we prioritized the flagged records by reviewing the deepest permitted wells first. As a result, we were able to identify nearly 15,000 more data records in which drilling occurred in a base year of interest.

Additionally, we verified base year data records in which the Spud Dates, Completed Drilling Dates, or permitted well depths were obvious errors. For example, permit ID = 618176 had a permitted well depth of 89,000 feet. In reviewing the TRC website, it was determined that the permitted well depth should have been 8,900 feet. Additional errors include Spud or Completed Drilling Dates that occurred prior to 1948 or after 2011. Also, it appears as if some years were transposed (e.g., 1990 vs. 1909) and these were corrected accordingly.

In some cases, drilling which occurred over multiple years was pro-rated for the base year of interest. In these situations, ERG calculated an "Average Drilling Rate" by dividing the permitted well depth by the number of drilling days, which is the number of days between the Completed Drilling Date and the Spud Date. The "Average Drilling Rate" was then used to pro-rate the total drilling days to each year. For example, permit ID = 486390 had a Spud Date of December 29, 2000, a Drilling Completion Date of January 8, 2001, and a total permitted well depth of 4,500 feet. Based on the Spud Date and Drilling End Date, it is assumed that drilling was continuous for 11 days. Therefore the "Average Drilling Rate" for this well was assumed to be 409.1 ft per day, and the 2000 pro-rated drilling was set to 1,227 feet for 2000 and 3,273 feet for 2001 (4,500 ft/11 days = 409.1 ft per day; 409.1 ft per day * 8 days = 3,272.8 ft; 409.1 ft per day * 3 days = 1,227.3 feet).

In total, ERG identified over 183,000 TRC permit records with drilling activity assigned to the target years. Each data record was also classified by three different wellbore

profile types defined during the 2009 study: "vertical well ≤ 7,000 feet"; "vertical well > 7,000 feet"; and "horizontal/directional well". These well type categories were selected to characterize three broadly different rig operation and engine type profiles, as discussed in detail in the 2009 report. The total amount of feet drilled was then summed to the county-level by wellbore profile type for each year.

ERG's processed drilling activity records covered the vast majority of TRC drilling records for the target years: of the 188,533 total wells drilled during the target years between 1990 and 2010 (as per the TRC database), ERG successfully characterized and processed 183,211 wells, or 97.2% of all recorded activity. The remaining wells could not be characterized adequately due to irresolvable data gaps or similar data inconsistencies.

4.1.2 Projected Activity

2011 through 2040 projected activity data were developed using 2010 as the base year activity data from the TRC and forecasting future activity based on US DOE Energy Information Administration (EIA) projections of oil and gas production for the Midcontinent, Southwest and Gulf Coast regions from the Annual Energy Outlook 2011, Reference Case. The EIA data tables (specifically Supplemental Tables 132 and 133) present estimated crude oil and natural gas production estimates for the years 2008-2035. The geographic level of the projected data is by EIA Region.

Portions of Texas fall into three EIA Regions: Gulf Coast (Region 2); Southwest (Region 4); and Midcontinent (Region 3). The majority of the State is in the Gulf Coast and Southwest EIA Regions. Only a small portion (area to the west of Oklahoma) is in the Midcontinent Region. Figure 4-1 shows the EIA regions and their coverage in Texas.

Figure 4-1. EIA Regions

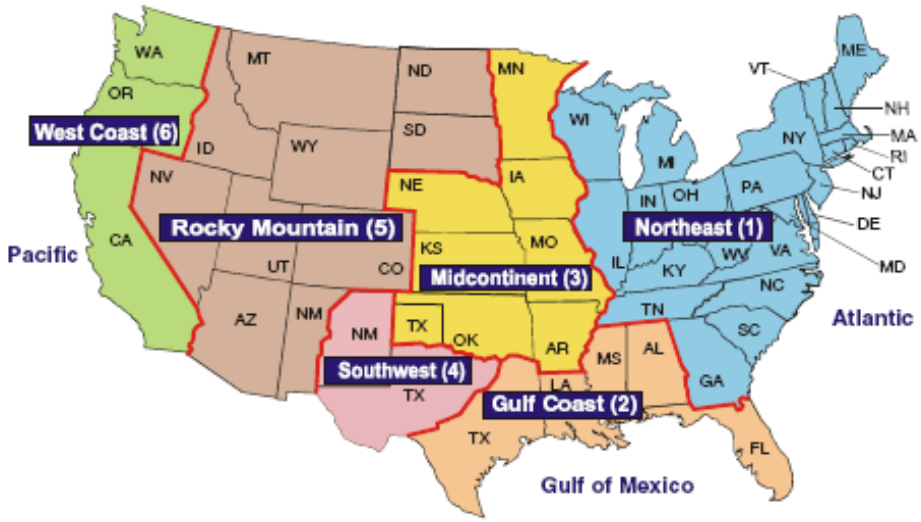
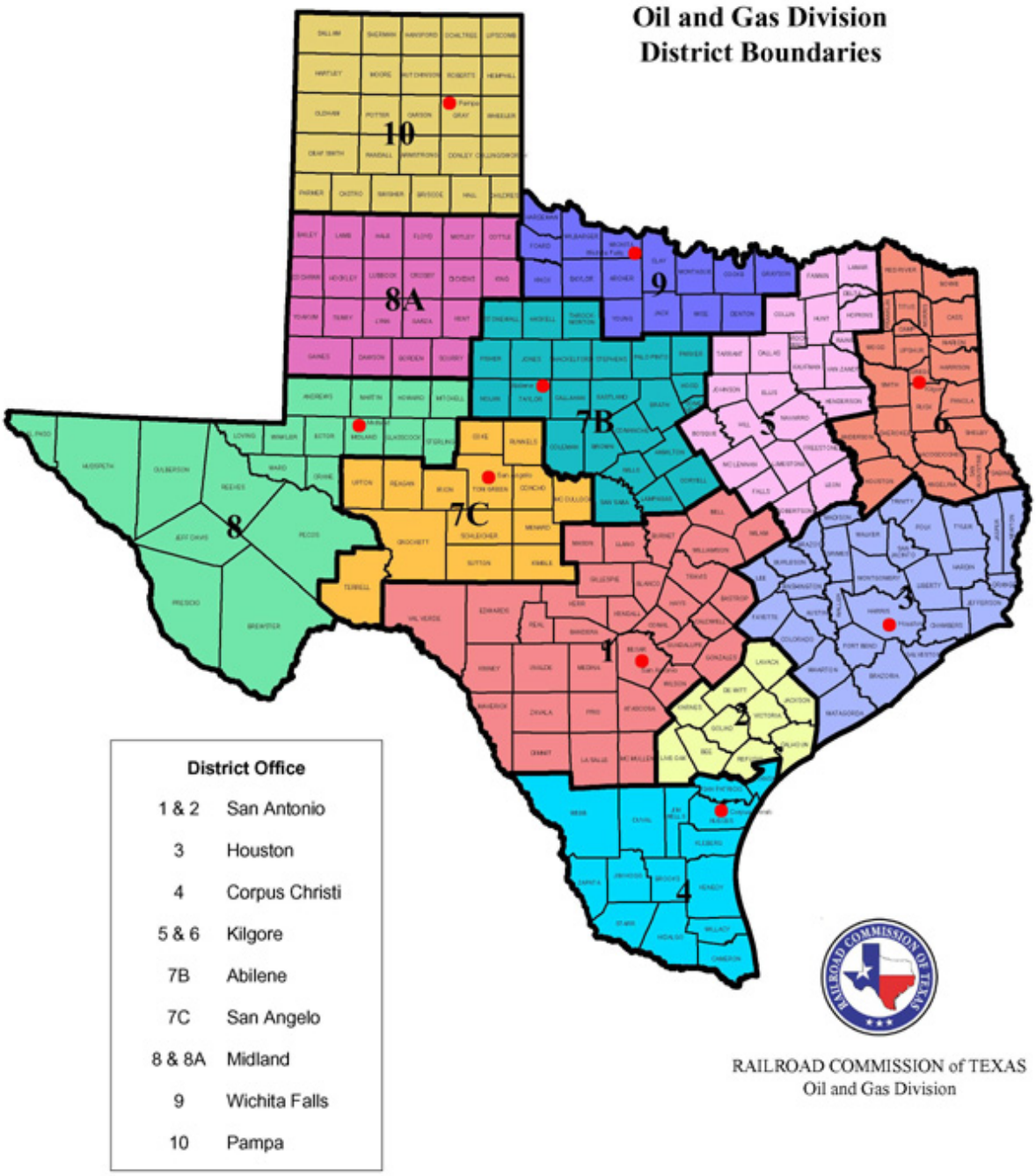


Figure 4-2 provides a county-level map indicating each of the TRC Districts.

Figure 4-2. TRC Districts[4]



[4] http://www.rrc.state.tx.us/forms/maps/ogdivisionmap.php

Using the above figures, ERG developed a direct correspondence between EIA regions and TRC regions, as follows:

- EIA Midcontinent => TRC District 10
- EIA Southwest => TRC Districts 7b, 7c, 8, 8a, 9
- EIA Gulf Coast => TRC Districts 1 - 6

Using these assignments ERG developed growth projections through 2035 for the three different county groupings - see Appendix B for county groups.

Table 4-1 and Table 4-2 show projected crude oil and natural gas production for the three relevant EIA Regions, from 2010 through 2035. The total percentage change for each year from 2011 through 2035 is presented relative to the base year of 2010.

This data was then used to calculate a projected growth factor (%) for each year from 2011 through 2035 for each county grouping by weighting the oil and gas percentage growth figures relative to the number of oil and gas wells completed statewide in 2010. (Growth rates for 2036 – 2040 are assumed to equal the 2035 rate). For example, the projected growth factor for 2011 for the EIA Gulf Coast (GC) region is calculated as follows:

2011 GC factor = ((% change from 2010 to 2011 in GC Crude Oil Production x number of oil well completions in 2010) + (% change from 2010 to 2011 in GC Natural Gas Production x number of gas well completions in 2010)) / (total number of oil and gas well completions in 2010)

Using the data in Table 4-1 and Table 4-2, combined with the statewide well completion counts, the projected growth factor for the EIA GC region in 2011 is:

2011 GC factor = ((9.8% x 5,392) + (-1.3% x 4,071)) / (5,392+ 4,071) = 5.0%

Table 4-3 shows the growth factors that were developed for each projected county grouping and year combination as a result of this analysis. These factors were then applied to the 2010 base year well depth totals by county to determine activity data for 2011 through 2035. These projections are based on the best data currently available, but should be revisited periodically given the volatile economic nature of oil and gas prices.

Table 4-1. Projected Crude Oil Production 2010-2035

	Crude Oil Production (MMBBL/day)													
EIA Region	**2010**	**2011**	**2012**	**2103**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Gulf Coast	0.53	0.58	0.60	0.62	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.72	0.73	0.75
Midcontinent	0.34	0.33	0.34	0.34	0.34	0.35	0.36	0.37	0.37	0.40	0.42	0.46	0.51	0.56
Southwest	0.94	0.97	0.99	1.01	1.02	1.03	1.05	1.07	1.09	1.11	1.11	1.10	1.11	1.11
% Change from 2010														
Gulf Coast		9.8%	13.2%	16.7%	18.1%	21.9%	24.8%	27.8%	31.2%	34.7%	36.4%	37.2%	38.7%	41.5%
Midcontinent		-5.3%	-2.1%	-0.7%	-0.3%	1.7%	4.5%	6.6%	8.8%	15.3%	21.2%	34.2%	49.0%	62.0%
Southwest		3.2%	5.6%	7.0%	8.7%	9.8%	11.2%	14.0%	16.2%	17.7%	18.2%	17.4%	17.6%	17.9%

	Crude Oil Production (MMBBL/day)											
EIA Region	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Gulf Coast	0.75	0.75	0.73	0.73	0.72	0.72	0.71	0.71	0.70	0.68	0.68	0.66
Midcontinent	0.60	0.62	0.64	0.65	0.65	0.65	0.66	0.65	0.64	0.64	0.62	0.60
Southwest	1.10	1.10	1.09	1.09	1.08	1.06	1.05	1.04	1.03	1.02	1.00	0.99
% Change from 2010												
Gulf Coast	41.5%	41.4%	39.4%	38.6%	36.9%	35.9%	35.7%	34.5%	33.5%	29.8%	28.1%	24.6%
Midcontinent	74.1%	79.9%	85.2%	87.9%	89.7%	89.7%	91.4%	90.0%	84.9%	84.6%	81.6%	75.4%
Southwest	17.3%	16.8%	15.9%	15.8%	14.5%	13.2%	11.9%	10.6%	9.2%	8.5%	6.0%	5.0%

Table 4-2. Projected Natural Gas Production 2010-2035

EIA Region	Natural Gas Production (trillion cubic feet)													
	2010	**2011**	**2012**	**2103**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Gulf Coast	4.25	4.19	4.21	4.28	4.28	4.26	4.16	4.09	4.03	3.99	4.00	4.00	4.01	3.97
Midcontinent	3.17	3.16	3.17	3.18	3.15	3.12	3.05	2.98	2.91	2.85	2.74	2.74	2.73	2.73
Southwest	4.25	4.18	4.14	4.16	4.14	4.13	4.07	4.01	3.96	3.90	3.90	3.88	3.90	3.92
% Change from 2010														
Gulf Coast		-1.3%	-1.0%	0.7%	0.9%	0.3%	-1.9%	-3.6%	-5.0%	-6.1%	-5.9%	-5.8%	-5.5%	-6.4%
Midcontinent		-0.2%	0.0%	0.5%	-0.6%	-1.4%	-3.7%	-6.0%	-8.0%	-10.1%	-13.4%	-13.6%	-13.7%	-14.0%
Southwest		-1.7%	-2.5%	-2.1%	-2.5%	-2.7%	-4.3%	-5.6%	-6.9%	-8.3%	-8.2%	-8.7%	-8.3%	-7.7%

EIA Region	Natural Gas Production (trillion cubic feet)											
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Gulf Coast	3.95	4.00	4.01	4.04	4.06	4.03	4.00	3.98	3.99	4.00	4.03	4.08
Midcontinent	2.70	2.70	2.68	2.67	2.67	2.62	2.59	2.58	2.57	2.58	2.58	2.61
Southwest	3.92	3.93	3.91	3.89	3.90	3.87	3.89	3.92	3.97	4.02	4.07	4.12
% Change from 2010												
Gulf Coast	-6.9%	-5.9%	-5.5%	-4.8%	-4.3%	-5.0%	-5.7%	-6.2%	-6.1%	-5.8%	-5.0%	-3.9%
Midcontinent	-14.8%	-14.8%	-15.3%	-15.6%	-15.8%	-17.3%	-18.2%	-18.4%	-18.9%	-18.6%	-18.4%	-17.6%
Southwest	-7.6%	-7.5%	-8.0%	-8.4%	-8.3%	-8.9%	-8.4%	-7.7%	-6.5%	-5.4%	-4.2%	-2.9%

Table 4-3. Weighted Average Projected Growth Factors 2011-2035+

Year	Gulf Coast	Midcontinent	Southwest
2011	5.02%	-3.11%	1.09%
2012	7.09%	-1.20%	2.12%
2013	9.82%	-0.18%	3.09%
2014	10.70%	-0.43%	3.88%
2015	12.61%	0.37%	4.42%
2016	13.31%	0.97%	4.53%
2017	14.29%	1.18%	5.57%
2018	15.63%	1.57%	6.26%
2019	17.15%	4.37%	6.51%
2020	18.20%	6.32%	6.84%
2021	18.70%	13.64%	6.17%
2022	19.69%	22.03%	6.46%
2023	20.89%	29.30%	6.89%
2024	20.68%	35.86%	6.59%
2025	21.05%	39.16%	6.35%
2026	20.08%	41.96%	5.62%
2027	19.93%	43.37%	5.39%
2028	19.18%	44.31%	4.69%
2029	18.30%	43.67%	3.69%
2030	17.89%	44.25%	3.17%
2031	16.99%	43.37%	2.73%
2032	16.46%	40.25%	2.45%
2033	14.48%	40.20%	2.52%
2034	13.86%	38.58%	1.61%
2035+	12.34%	35.39%	1.60%

Appendix C contains a summary of the total well depth by county and year for each model rig well type category.

4.2 Model Rig Emission Profiles

4.2.1 Model Rig Engine Profiles

The 2009 study established rig engine profiles for three distinct model rig categories for the following well types and depths based on the results of the data collection survey:

- Vertical wells less than or equal to 7,000 feet;
- Vertical wells greater than 7,000 feet; and
- Horizontal/Directional wells.

For each of these rig categories, a model rig engine profile was developed. In order for the model rig engine profile data to be applied consistently to the TRC activity data, the survey results were normalized to a 1,000 foot drilling depth. This was accomplished by dividing the total drilling hours for each engine included in each survey by the well depth for that survey to obtain the hours of operation per engine per 1,000 feet of drilling depth.

As the engine profiles and functions for engines used on mechanical rigs and electrical rigs are distinctly different, separate engine profiles for mechanical and electrical rigs were developed for each model rig well type category.

The following average engine parameters were calculated for each model rig well type category using a weighted average for each parameter based on the number of wells associated with each survey:

- Number of engines by rig type (i.e., mechanical draw works, mud pumps, and generators; electrical rig engines; and completion engines)
- Engine age
- Engine size (hp)
- Engine on-time (hours/1,000 feet drilled)
- Overall average load (%)

The weighted averaged engine parameters developed for each model rig category by rig type in the 2009 study are summarized in Table 4-4.

Table 4-4. Model Rig Engine Parameters

Model Rig Category	Rig Type	Engine Type	# of Engines	Average Age (yrs)	Engine Size (hp)	Hours/1,000 ft drilled	Average Load (%)
Vertical <= 7,000 ft	Mechanical	Draw Works	1.60	7	442	30.8	51.8
		Mud Pumps	1.69	6	428	29.4	45.9
		Generator	0.97	4	330	28.3	70.4
Vertical > 7,000 ft	Mechanical	Draw Works	2.01	25	455	35.9	47.4
		Mud Pumps	1.62	18	761	33.2	46.0
		Generator	2.00	10	407	19.3	78.7
	Electrical		2.15	2	1,381	62.6	48.5
Horizontal/ Directional	Mechanical	Draw Works	2.00	15	483	50.1	41.1
		Mud Pumps	2.00	6	1,075	36.4	42.6
		Generator	2.00	10	390	26.8	69.0
	Electrical		2.03	2	1,346	47.3	52.5
All	All	Completion	1.00	Default	350	10.0	43.0

As can be seen in Table 4-4, the expected trend toward larger engine sizes and more hours required per 1,000 feet for the deeper vertical wells and the horizontal/directional wells was verified. The older engine ages for the mechanical rigs used on the deeper vertical wells and the horizontal/directional wells are based on several surveys received for these well types that covered a large number of wells drilled by rigs with older engines. However, as noted in the 2009 study report, the future trend for these types of wells is towards the use of electrical rigs, and the average age of the engines used on the electrical rigs for these well types is only two years.

4.2.2 Model Rig Emission Factors

Using the model rig engine parameters presented in Table 4-4, EPA's NONROAD2008a model was modified to develop criteria pollutant emission factors for each model rig well type category for each year of the inventory (1990, 1993, 1996, and 1999 through 2040). Use of the NONROAD model allowed for expected reductions in emissions over time due to the phasing in of EPA's emissions standards for Non-Road diesel engines. [5]

Following the same methodology used in the 2009 emission inventory study, ERG modified the ACTIVITY.DAT file within NONROAD to reflect the appropriate hours per year and load factors for the required engine types (mechanical and electrical engines for each of the three rig types). Modifications were made for SCC 2270010010 (Diesel Other Oil Field Equipment). ERG also modified the TX.POP file to reflect the appropriate average hp for the engine type in question, and set the equipment population count to 1 in order to ease post-processing calculations. In addition, default NONROAD OPT files (input files containing basic model run information) were modified to reflect the statewide diesel fuel sulfur levels (see below) for each scenario year of interest. Accordingly, sets of OPT, activity, and population files were developed to model each well type/engine type/scenario year combination for this analysis.

Hazardous air pollutant (HAP) emission factors were developed by speciating the NONROAD emission factors based on HAP emissions profiles obtained from the California Air Resource Board's Speciation Profile Database (ARB, 2001). The specific speciation profiles used were Profile #818 for TOG and Profile #425 for PM. This methodology is consistent with the prior 2009 emission inventory study approach, as well as the speciation method used within the TCEQ's TexN emissions model. The HAP speciation factors used are presented in Table 4-5 and Table 4-6.

[5] While the NONROAD model was used to calculate drilling activity emissions (in order to more accurately capture emission standard phase in impacts), these emissions are actually classified as area sources emissions and reported as such to the TCEQ.

Table 4-5. PM_{10} Speciation Factors

HAP	HAP CAS #	Weight Fraction of PM_{10}
Antimony	7440360	0.000036
Arsenic	7440382	0.000005
Cadmium	7440439	0.000040
Cobalt	7440484	0.000011
Chlorine	7782505	0.000344
Lead	7439921	0.000042
Manganese	7439965	0.000040
Nickel	7440020	0.000019
Mercury	7439976	0.000030
Phosphorous	7723140	0.000127
Selenium	7782492	0.000010

Table 4-6. TOG Speciation Factors

HAP	HAP CAS #	Weight Fraction of TOG
1,3-butadiene	106990	0.002
2,2,4-trimethylpentane	540841	0.003
Acetaldehyde	75070	0.074
Benzene	71432	0.02
Cumene	98828	2E-04
Ethylbenzene	100414	0.003
Formaldehyde	50000	0.147
Methanol	67561	3E-04
m-xylene	108383	0.006
Naphthalene	91203	9E-04
n-hexane	110543	0.002
o-xylene	95476	0.003
Propionaldehyde	123386	0.01
p-xylene	106423	0.001
Styrene	100425	6E-04
Toluene	108883	0.015

SO_2 emissions were based on fuel sulfur content profiles for Texas obtained from historical fuel sampling data performed for the TCEQ. The average diesel sulfur content (% weight) for a particular analysis year was developed using the county-level fuel parameter data contained in TCEQ's TexN model, weighted by the number of wells in each county in 2008. The statewide average diesel sulfur content values calculated are presented in Table 4-7 reflecting the reduced sulfur requirements over time.

Table 4-7. Annual Weighted Average Diesel Fuel Sulfur

Year	Sulfur (% weight)
1990	0.3015
1993	0.2693
1996	0.3138
1999	0.1733
2000	0.1717
2001	0.1708
2002	0.1706
2003	0.1700
2004	0.1692
2005	0.1678
2006	0.1665
2007	0.0320
2008	0.0317
2009	0.0321
2010+	0.0015

Mass emissions per 1,000 feet of drilling for each engine type were derived from NONROAD outputs. The activity levels entered into NONROAD corresponded to the hours required to drill 1,000 feet, so NONROAD outputs were uniformly normalized to these units. Total emissions for each engine type/drill rig category combination were calculated by dividing the NONROAD output emissions total by the fractional engine population for the appropriate engine model year (from NONROAD's by-model-year output), and then multiplying by the average number of engines for each drill rig type. For example, the average age for a shallow well mechanical draw works engine is 7 years. Therefore for a 1990 calendar year run, emissions for a 1983 engine are first identified in the NONROAD by-model-year output. Since the NONROAD population file was set to equal one unit (corresponding to all model years), NONROAD calculates the "population" of 7 year old engines to be 0.0386 (i.e., 3.86% of all engines operating in 1990). In order to calculate total emissions per 1,000 feet of drilling activity for this engine, the mass emissions associated with this model year are first divided by this population to obtain the mass emissions rate per year for one engine (e.g., 0.0015 tons per year CO per 0.0386 engines = 0.039 tons per year per unit). Finally, this values is multiplied by the average number of engines of this type for the given well type (e.g., 1.6 mechanical draw works engines per shallow well drill rig) to obtain the emission factor expressed as mass emissions for each engine category/well type combination per 1,000 feet of drilling activity.

Total hydrocarbon (THC) exhaust emissions from the NONROAD model were converted to VOC and TOG using ratios of 1.053 and 1.070, respectively (U.S. EPA, 2005a). Crankcase THC emissions were assumed to be equivalent to both VOC and TOG (U.S.

EPA, 2005b). For diesel Non-Road engines, PM_{10} is assumed to be equivalent to PM, while the $PM_{2.5}$ fraction of PM_{10} is estimated to be 0.97 (U.S. EPA, 2005a).

Table 4-8, Table 4-9, and Table 4-10 contain the criteria pollutant emission factors developed for each model rig well type category for the emission inventory target years. Note that emission factors for uncontrolled emission inventory estimates were set equal to the 1990 factors below, as these pre-date the introduction of diesel engine controls.

Table 4-8. Emission Factors for Vertical Wells <= 7,000 feet (tons/1,000 feet)

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
1990	0.25171	0.03063	0.04040	0.15717	0.03131	0.03037	0.04104
1993	0.25444	0.02738	0.03638	0.14060	0.02670	0.02590	0.03696
1996	0.26302	0.03197	0.02351	0.08748	0.01316	0.01276	0.02389
1999	0.26260	0.01766	0.02331	0.08677	0.01185	0.01150	0.02368
2000	0.24601	0.01751	0.01968	0.07693	0.01041	0.01010	0.01999
2001	0.24580	0.01742	0.01961	0.07669	0.01036	0.01005	0.01992
2002	0.22069	0.01741	0.01411	0.06173	0.00819	0.00794	0.01433
2003	0.19156	0.01737	0.00773	0.04439	0.00567	0.00550	0.00785
2004	0.19135	0.01729	0.00767	0.04415	0.00562	0.00545	0.00779
2005	0.18171	0.01715	0.00741	0.04125	0.00559	0.00542	0.00753
2006	0.18138	0.01702	0.00735	0.04102	0.00553	0.00537	0.00747
2007	0.16568	0.00327	0.00699	0.03648	0.00444	0.00431	0.00710
2008	0.14886	0.00324	0.00662	0.03164	0.00446	0.00433	0.00672
2009	0.14675	0.00328	0.00652	0.03092	0.00443	0.00430	0.00663
2010	0.13275	0.00015	0.00642	0.03010	0.00400	0.00388	0.00652
2011	0.12988	0.00015	0.00634	0.02951	0.00394	0.00382	0.00644
2012	0.11200	0.00015	0.00628	0.02926	0.00368	0.00357	0.00638
2013	0.08760	0.00015	0.00619	0.02854	0.00337	0.00327	0.00629
2014	0.08282	0.00015	0.00611	0.02777	0.00332	0.00322	0.00621
2015	0.07454	0.00014	0.00574	0.02223	0.00266	0.00258	0.00583
2016	0.07407	0.00014	0.00570	0.02204	0.00263	0.00255	0.00579
2017	0.06190	0.00013	0.00519	0.01384	0.00166	0.00161	0.00527
2018	0.04010	0.00011	0.00459	0.00433	0.00053	0.00052	0.00467
2019	0.03966	0.00011	0.00456	0.00417	0.00051	0.00049	0.00463
2020	0.02752	0.00011	0.00452	0.00401	0.00049	0.00047	0.00460
2021	0.01353	0.00011	0.00450	0.00388	0.00047	0.00046	0.00457
2022	0.01316	0.00011	0.00448	0.00376	0.00045	0.00044	0.00455
2023	0.01281	0.00011	0.00446	0.00365	0.00044	0.00043	0.00453
2024	0.01246	0.00011	0.00444	0.00354	0.00042	0.00041	0.00451
2025	0.01207	0.00011	0.00442	0.00342	0.00041	0.00040	0.00450
2026	0.01176	0.00011	0.00441	0.00333	0.00040	0.00038	0.00448
2026	0.01148	0.00011	0.00440	0.00325	0.00038	0.00037	0.00447
2027	0.01121	0.00011	0.00439	0.00317	0.00037	0.00036	0.00446

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
2027	0.01095	0.00011	0.00438	0.00310	0.00036	0.00035	0.00445
2028	0.01071	0.00011	0.00437	0.00303	0.00035	0.00034	0.00444
2028	0.01049	0.00011	0.00436	0.00296	0.00035	0.00034	0.00443
2029	0.01030	0.00011	0.00435	0.00291	0.00034	0.00033	0.00442
2029	0.01012	0.00011	0.00434	0.00285	0.00033	0.00032	0.00441
2030	0.00995	0.00011	0.00434	0.00280	0.00032	0.00031	0.00441
2030	0.00980	0.00011	0.00433	0.00275	0.00032	0.00031	0.00440
2031	0.00966	0.00011	0.00433	0.00271	0.00031	0.00030	0.00440
2031	0.00955	0.00011	0.00432	0.00269	0.00031	0.00030	0.00439
2032	0.00944	0.00011	0.00432	0.00267	0.00031	0.00030	0.00439
2033	0.00935	0.00011	0.00432	0.00265	0.00031	0.00030	0.00439
2034	0.00928	0.00011	0.00432	0.00263	0.00030	0.00029	0.00439
2035	0.25171	0.03063	0.04040	0.15717	0.03131	0.03037	0.04104
2036	0.25444	0.02738	0.03638	0.14060	0.02670	0.02590	0.03696
2036	0.26302	0.03197	0.02351	0.08748	0.01316	0.01276	0.02389
2037	0.26260	0.01766	0.02331	0.08677	0.01185	0.01150	0.02368
2037	0.24601	0.01751	0.01968	0.07693	0.01041	0.01010	0.01999
2038	0.24580	0.01742	0.01961	0.07669	0.01036	0.01005	0.01992
2038	0.22069	0.01741	0.01411	0.06173	0.00819	0.00794	0.01433
2039	0.19156	0.01737	0.00773	0.04439	0.00567	0.00550	0.00785
2040	0.19135	0.01729	0.00767	0.04415	0.00562	0.00545	0.00779

Table 4-9- Emission Factors for Vertical Wells > 7,000 feet (tons/1,000 feet)

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
1990	0.49496	0.05948	0.06914	0.26759	0.05123	0.04969	0.07024
1993	0.49504	0.05313	0.06903	0.26713	0.05060	0.04908	0.07013
1996	0.49495	0.06190	0.06889	0.26660	0.05118	0.04964	0.06998
1999	0.49879	0.03421	0.06243	0.24004	0.04199	0.04073	0.06342
2000	0.49870	0.03389	0.06240	0.23995	0.04195	0.04069	0.06339
2001	0.49849	0.03372	0.06234	0.23971	0.04189	0.04063	0.06332
2002	0.46064	0.03370	0.05520	0.20664	0.03828	0.03713	0.05608
2003	0.46042	0.03358	0.05514	0.20639	0.03822	0.03707	0.05601
2004	0.46020	0.03342	0.05508	0.20616	0.03816	0.03702	0.05595
2005	0.45996	0.03315	0.05500	0.20588	0.03809	0.03695	0.05587
2006	0.43976	0.03294	0.03956	0.15015	0.02524	0.02448	0.04019
2007	0.43941	0.00633	0.03950	0.14992	0.02305	0.02236	0.04012
2008	0.41484	0.00627	0.03791	0.14969	0.02320	0.02250	0.03851
2009	0.41450	0.00635	0.03785	0.14947	0.02316	0.02247	0.03845
2010	0.41067	0.00030	0.03757	0.14922	0.02266	0.02198	0.03817
2011	0.38828	0.00030	0.03679	0.14474	0.02272	0.02204	0.03737
2012	0.38788	0.00030	0.03673	0.14449	0.02268	0.02200	0.03731
2013	0.36209	0.00027	0.03066	0.11096	0.01306	0.01267	0.03114
2014	0.36162	0.00027	0.03061	0.11076	0.01303	0.01264	0.03110

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
2015	0.36110	0.00027	0.03056	0.11054	0.01299	0.01260	0.03105
2016	0.34210	0.00027	0.03052	0.11036	0.01274	0.01235	0.03101
2017	0.33770	0.00027	0.02778	0.09816	0.01199	0.01163	0.02822
2018	0.29887	0.00027	0.02054	0.06434	0.00828	0.00804	0.02086
2019	0.29843	0.00027	0.02050	0.06418	0.00826	0.00801	0.02083
2020	0.29800	0.00027	0.02047	0.06402	0.00824	0.00799	0.02079
2021	0.25188	0.00026	0.01265	0.03544	0.00431	0.00418	0.01285
2022	0.25151	0.00026	0.01263	0.03532	0.00429	0.00416	0.01283
2023	0.25116	0.00026	0.01261	0.03521	0.00428	0.00415	0.01281
2024	0.30891	0.00034	0.01574	0.04822	0.00639	0.00620	0.01599
2025	0.30851	0.00034	0.01572	0.04810	0.00637	0.00618	0.01597
2026	0.36940	0.00041	0.01828	0.05992	0.00813	0.00788	0.01857
2026	0.18307	0.00026	0.00997	0.02947	0.00456	0.00442	0.01013
2027	0.18042	0.00026	0.00991	0.02873	0.00455	0.00442	0.01007
2027	0.15075	0.00023	0.01184	0.02869	0.00363	0.00352	0.01203
2028	0.15051	0.00023	0.01183	0.02862	0.00362	0.00351	0.01202
2028	0.12694	0.00023	0.01182	0.02859	0.00332	0.00322	0.01201
2029	0.12178	0.00023	0.01177	0.02786	0.00329	0.00319	0.01195
2029	0.12160	0.00023	0.00904	0.01605	0.00256	0.00248	0.00918
2030	0.12143	0.00023	0.00903	0.01599	0.00255	0.00247	0.00918
2030	0.12128	0.00023	0.00903	0.01595	0.00254	0.00247	0.00917
2031	0.10549	0.00021	0.00838	0.00510	0.00123	0.00119	0.00852
2031	0.10538	0.00021	0.00838	0.00507	0.00122	0.00119	0.00851
2032	0.10527	0.00021	0.00837	0.00505	0.00122	0.00119	0.00851
2033	0.08953	0.00021	0.00837	0.00503	0.00122	0.00118	0.00851
2034	0.08946	0.00021	0.00837	0.00501	0.00122	0.00118	0.00850
2035	0.49496	0.05948	0.06914	0.26759	0.05123	0.04969	0.07024
2036	0.49504	0.05313	0.06903	0.26713	0.05060	0.04908	0.07013
2036	0.49495	0.06190	0.06889	0.26660	0.05118	0.04964	0.06998
2037	0.49879	0.03421	0.06243	0.24004	0.04199	0.04073	0.06342
2037	0.49870	0.03389	0.06240	0.23995	0.04195	0.04069	0.06339
2038	0.49849	0.03372	0.06234	0.23971	0.04189	0.04063	0.06332
2038	0.46064	0.03370	0.05520	0.20664	0.03828	0.03713	0.05608
2039	0.46042	0.03358	0.05514	0.20639	0.03822	0.03707	0.05601
2040	0.46020	0.03342	0.05508	0.20616	0.03816	0.03702	0.05595

Table 4-10. Emission Factors for Directional/Horizontal Wells (tons/1,000 feet)

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
1990	0.62480	0.07390	0.06988	0.26540	0.04582	0.04444	0.07098
1993	0.62488	0.06601	0.06977	0.26494	0.04506	0.04371	0.07087
1996	0.62938	0.07696	0.06288	0.23655	0.03852	0.03736	0.06388
1999	0.63098	0.04251	0.05971	0.22359	0.03236	0.03138	0.06066

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
2000	0.63089	0.04212	0.05968	0.22350	0.03231	0.03134	0.06063
2001	0.63068	0.04190	0.05962	0.22326	0.03224	0.03128	0.06056
2002	0.52031	0.04192	0.03887	0.12698	0.02177	0.02112	0.03949
2003	0.52286	0.04178	0.03473	0.10983	0.01724	0.01672	0.03528
2004	0.52264	0.04159	0.03467	0.10959	0.01718	0.01666	0.03522
2005	0.52241	0.04124	0.03459	0.10932	0.01710	0.01659	0.03514
2006	0.48263	0.04095	0.02674	0.07816	0.01340	0.01300	0.02716
2007	0.48228	0.00787	0.02668	0.07792	0.01069	0.01037	0.02710
2008	0.41103	0.00780	0.02216	0.07769	0.01122	0.01089	0.02251
2009	0.41069	0.00790	0.02210	0.07747	0.01119	0.01085	0.02245
2010	0.40019	0.00037	0.02140	0.07722	0.01062	0.01030	0.02174
2011	0.35517	0.00037	0.01617	0.06470	0.00928	0.00900	0.01643
2012	0.33742	0.00037	0.01502	0.06445	0.00937	0.00909	0.01526
2013	0.25166	0.00030	0.02051	0.06399	0.00675	0.00654	0.02084
2014	0.24871	0.00030	0.02031	0.06379	0.00674	0.00653	0.02063
2015	0.24323	0.00030	0.01995	0.06357	0.00674	0.00654	0.02027
2016	0.22416	0.00030	0.01972	0.06064	0.00664	0.00644	0.02004
2017	0.20118	0.00028	0.01322	0.02658	0.00392	0.00380	0.01343
2018	0.19951	0.00028	0.01316	0.02607	0.00390	0.00378	0.01337
2019	0.19907	0.00028	0.01313	0.02591	0.00387	0.00376	0.01334
2020	0.19864	0.00028	0.01309	0.02575	0.00385	0.00374	0.01330
2021	0.18028	0.00028	0.01092	0.01335	0.00270	0.00262	0.01109
2022	0.17734	0.00028	0.01087	0.01289	0.00267	0.00259	0.01105
2023	0.17698	0.00028	0.01085	0.01278	0.00266	0.00258	0.01103
2024	0.17076	0.00028	0.01084	0.01267	0.00264	0.00256	0.01101
2025	0.17036	0.00028	0.01082	0.01255	0.00263	0.00255	0.01099
2026	0.16196	0.00027	0.01047	0.00688	0.00194	0.00189	0.01064
2026	0.16168	0.00027	0.01046	0.00680	0.00193	0.00187	0.01063
2027	0.16141	0.00027	0.01045	0.00672	0.00192	0.00186	0.01062
2027	0.15306	0.00027	0.01044	0.00665	0.00191	0.00185	0.01061
2028	0.15281	0.00027	0.01043	0.00658	0.00190	0.00185	0.01060
2028	0.15259	0.00026	0.01042	0.00652	0.00189	0.00184	0.01059
2029	0.15240	0.00026	0.01041	0.00646	0.00189	0.00183	0.01058
2029	0.15222	0.00026	0.01041	0.00640	0.00188	0.00182	0.01057
2030	0.15206	0.00026	0.01040	0.00635	0.00187	0.00182	0.01057
2030	0.15190	0.00026	0.01039	0.00630	0.00187	0.00181	0.01056
2031	0.15177	0.00026	0.01039	0.00627	0.00186	0.00181	0.01056
2031	0.15165	0.00026	0.01039	0.00624	0.00186	0.00180	0.01055
2032	0.15154	0.00026	0.01038	0.00622	0.00186	0.00180	0.01055
2033	0.15146	0.00026	0.01038	0.00620	0.00185	0.00180	0.01055
2034	0.15138	0.00026	0.01038	0.00618	0.00185	0.00180	0.01055
2035	0.62480	0.07390	0.06988	0.26540	0.04582	0.04444	0.07098
2036	0.62488	0.06601	0.06977	0.26494	0.04506	0.04371	0.07087
2036	0.62938	0.07696	0.06288	0.23655	0.03852	0.03736	0.06388

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	TOG
2037	0.63098	0.04251	0.05971	0.22359	0.03236	0.03138	0.06066
2037	0.63089	0.04212	0.05968	0.22350	0.03231	0.03134	0.06063
2038	0.63068	0.04190	0.05962	0.22326	0.03224	0.03128	0.06056
2038	0.52031	0.04192	0.03887	0.12698	0.02177	0.02112	0.03949
2039	0.52286	0.04178	0.03473	0.10983	0.01724	0.01672	0.03528
2040	0.52264	0.04159	0.03467	0.10959	0.01718	0.01666	0.03522

4.3 Emission Estimation Methodology

Once the total depth drilled per year was aggregated by model rig well type category, and the emission factor profile for each model rig well type category was developed, county level emissions for each model rig well type category were estimated by multiplying the total depth drilled by county by the emission factors developed through use of the 2009 study survey data and the NONROAD model, as follows:

$$\text{Epoll/type} = (\text{Depth (1,000 feet/yr)}) \times (\text{EFpoll (tons/1,000 feet)})$$

Where:

Epoll/type	=	Emissions of pollutant for each county by model rig well type category (tons/yr)
Depth	=	Total depth drilled in model rig well type category by county (1,000feet/yr)
EFpoll	=	Pollutant emission factor (tons/1,000 feet)

This process is repeated for each of the well category/engine type combinations of interest – for example, mechanical draw works engines used for shallow vertical wells (< 7,000 feet).

For 2006 onward, NO_x emission estimates for the 110 counties in the eastern half of Texas subject to the Texas Low Emission Diesel (TxLED) program were adjusted downward by 6.2% to account for the effect of the rule. [6] Table 4-11 identifies the counties where this adjustment was made.

[6] The TxLED program requirements initiated in 2006, so these adjustments were not applied to the 2002 and 2005 modeling scenarios.

Table 4-11. TxLED Counties

Anderson	Denton	Johnson	Robertson
Angelina	Ellis	Karnes	Rockwall
Aransas	Falls	Kaufman	Rusk
Atascosa	Fannin	Lamar	Sabine
Austin	Fayette	Lavaca	San Jacinto
Bastrop	Franklin	Lee	San Patricio
Bee	Freestone	Leon	San Augustine
Bell	Fort Bend	Liberty	Shelby
Bexar	Galveston	Limestone	Smith
Bosque	Goliad	Live Oak	Somervell
Bowie	Gonzales	Madison	Tarrant
Brazoria	Grayson	Marion	Titus
Brazos	Gregg	Matagorda	Travis
Burleson	Grimes	McLennan	Trinity
Caldwell	Guadalupe	Milam	Tyler
Calhoun	Hardin	Montgomery	Upshur
Camp	Harris	Morris	Van Zandt
Cass	Harrison	Nacogdoches	Victoria
Chambers	Hays	Navarro	Walker
Cherokee	Henderson	Newton	Waller
Collin	Hill	Nueces	Washington
Colorado	Hood	Orange	Wharton
Comal	Hopkins	Panola	Williamson
Cooke	Houston	Parker	Wilson
Coryell	Hunt	Polk	Wise
Dallas	Jackson	Rains	
De Witt	Jasper	Red River	
Delta	Jefferson	Refugio	

For counties subject to TxLED requirements, NO_x emissions were estimated as follows:

$$\text{ENOx-type} = (\text{Depth (1,000 feet/yr)}) \times (\text{EFNOx (tons/1,000 feet)}) \times (0.938)$$

Where:

ENOx-type	=	Emissions of NOx for each county by model rig well type category (tons/yr)
Depth	=	Total depth drilled in model rig well type category by county (1,000 feet/yr)
EFNOx	=	NOx emission factor (tons/1,000 feet)
(0.938)	=	Adjustment Factor to account for 6.2% TxLED reduction

Total county level emissions were then determined by summing county level emissions for each of the three model rig categories for a given year.

4.3.1 Example Emission Calculations

Using the data above, CO emissions in 2008 for Anderson County from vertical wells > 7,000 feet are estimated as follows:

ECO = (Depth (1,000 feet/yr)) x (EFpoll (tons/1,000 feet)), or
ECO = (85 (1,000 feet/yr)) x (1.50E-01 (tons/1,000 feet))
ECO = 12.7 (tons/yr)

As Anderson County is subject to the TxLED requirements, NO_x emissions in 2008 for Anderson County from vertical wells > 7,000 feet are estimated as follows:

ENO_x = (Depth (1,000 feet/yr)) x (EFpoll (tons/1,000 feet)) x (0.938), or
ENO_x = (85 (1,000 feet/yr)) x (4.15E-01 (tons/1,000 feet)) x (0.938)
ENO_x = 33.1 (tons/yr)

4.4 Results

4.4.1 Emission Summary

Tables 4-12, through 4-15, as well as Figures 4-3 through 4-9 summarize the statewide annual and ozone-season daily criteria emissions totals for diesel engine drill rigs, for both controlled and uncontrolled scenarios. An Uncontrolled scenario was developed by combining year-specific activity levels with the 1990 emission rates generated using the NONROAD2008 model. The diesel engines operating in 1990 were not subject to emission controls and represent "uncontrolled" conditions. The Controlled scenario reflects the emission controls in place for any given year, and are accounted for in the NONROAD2008 model emission factors output for each analysis year. Depending upon the analysis year in question, one or more of the following emission controls are reflected in the Controlled scenario:

- Federal Emission Standards for Heavy-Duty and Non-Road Engines - "1998 HD and Non-Road Rule";
- Tier 1, 2 and Tier 3 Emission Standards: Control of Emissions of Air Pollution from Non-Road Diesel Engines - "Tier 1, 2 and 3 Rule"; and
- Clean Air Non-Road Diesel - Tier 4 Final Rule – "Tier 4 Rule", including ultra-low sulfur requirements for Non-Road diesel fuel.

In addition, the impact of the state TxLED rule is also included in all Controlled scenario estimates after 2005, as described above. None of these rules are accounted for in the Uncontrolled scenario.

HAP emissions estimates and by-county breakouts were provided in the electronic XML files submitted to the TCEQ under Task 2b of this study. Appendix A also provides the statewide emissions estimates for HAPs, while Appendix D provides county level breakouts for statewide annual and ozone season day emissions.

Table 4-12. Statewide Annual Emissions Totals (Tons/Year), Controlled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
1990	25,308	3,037	3,462	13,366	2,533	2,457
1993	29,354	3,141	3,940	15,193	2,828	2,743
1996	33,037	4,093	4,044	15,502	2,822	2,737
1999	24,159	1,647	2,769	10,568	1,760	1,707
2000	33,578	2,290	3,798	14,570	2,422	2,350
2001	38,960	2,641	4,410	16,910	2,810	2,726
2002	27,974	2,100	2,955	11,027	1,978	1,919
2003	37,220	2,825	3,803	14,234	2,548	2,471
2004	40,164	3,040	4,047	15,057	2,688	2,607
2005	47,798	3,606	4,788	17,706	3,163	3,068
2006	52,497	4,290	4,135	15,235	2,539	2,463
2007	57,197	909	4,443	16,071	2,392	2,320
2008	59,261	1,033	4,593	17,745	2,696	2,615
2009	29,231	523	2,202	8,464	1,282	1,244
2010	24,531	21	1,846	7,182	1,056	1,024
2011	23,254	21	1,725	6,869	1,047	1,016
2012	22,920	22	1,716	6,949	1,060	1,028
2013	19,878	19	1,687	5,893	672	652
2014	19,875	20	1,691	5,916	675	655
2015	19,819	20	1,693	5,897	673	653
2016	18,711	20	1,691	5,826	663	643
2017	17,954	19	1,417	4,375	553	537
2018	16,446	19	1,164	3,085	413	400
2019	16,545	19	1,170	3,096	414	402
2020	16,475	20	1,175	3,102	415	402
2021	14,182	19	832	1,712	240	233
2022	14,201	19	837	1,705	240	233
2023	14,308	19	843	1,711	242	234
2024	16,194	22	956	2,178	318	308
2025	16,186	22	956	2,170	317	307
2026	18,006	24	1,032	2,409	357	346
2027	11,359	19	732	1,307	228	221
2028	11,190	19	725	1,269	226	219
2029	9,817	18	787	1,254	190	185
2030	9,762	18	783	1,244	189	183
2031	8,878	17	778	1,233	177	172
2032	8,649	17	772	1,200	175	170

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2033	8,566	17	671	779	148	143
2034	8,490	17	665	770	146	142
2035	8,410	17	660	761	145	140
2036	7,869	16	637	387	99	96
2037	7,861	16	637	385	99	96
2038	7,853	16	637	384	99	96
2039	7,316	16	637	382	99	96
2040	7,311	16	637	381	99	96

Figure 4-3. Statewide Drilling Rig Emissions – Controlled Scenario (NO_x and CO Tons/Year)

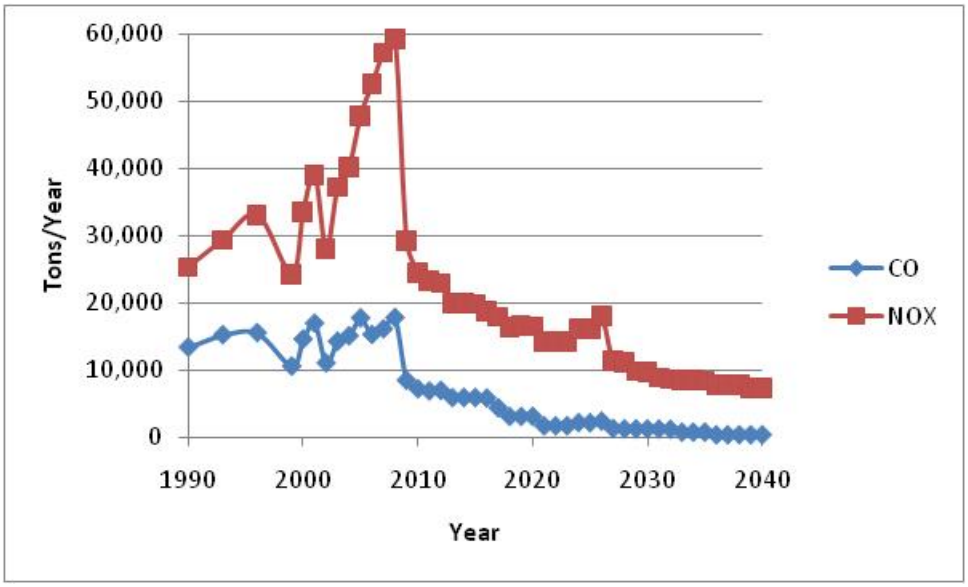


Figure 4-4. Statewide Drilling Rig Emissions – Controlled Scenario (VOC and SO_2 Tons/Year)

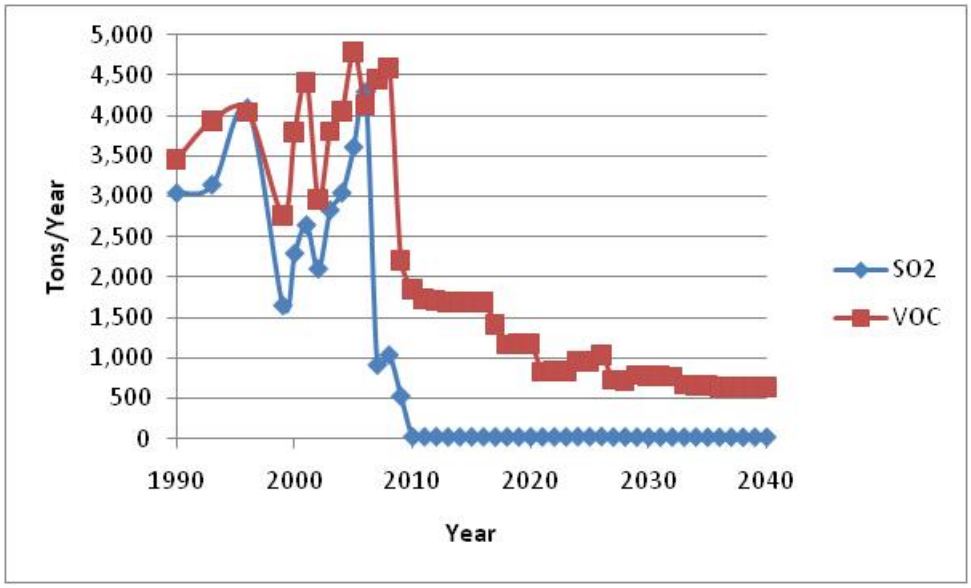
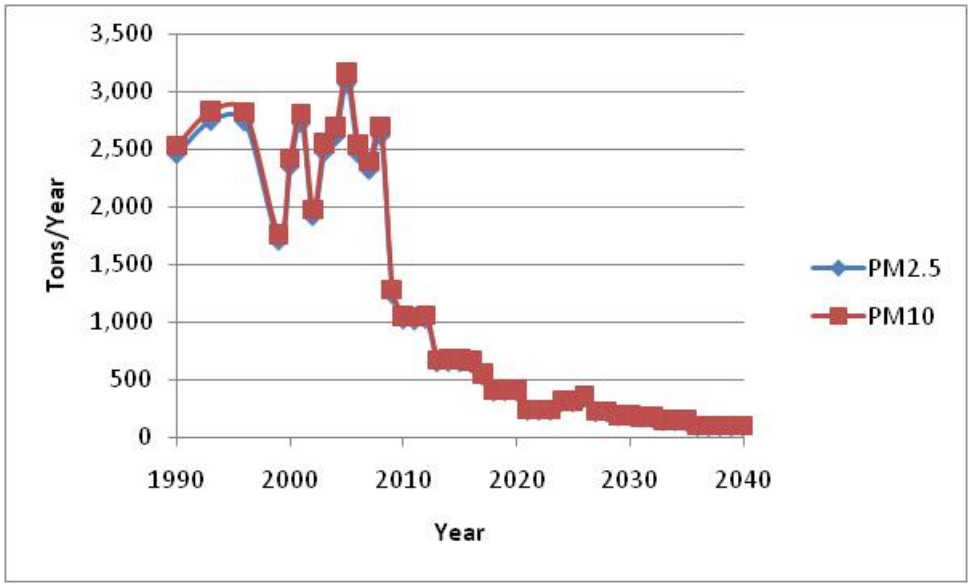


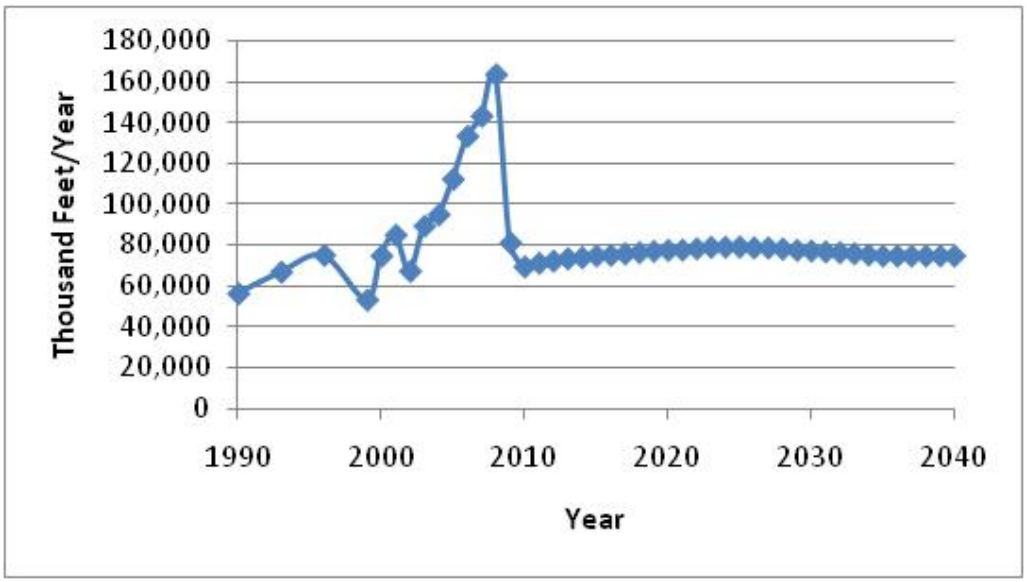
Figure 4-5. Statewide Drilling Rig Emissions – Controlled Scenario (PM_{10} and $PM_{2.5}$ Tons/Year)



Figures 4.3 through 4.5 show a general increase in most pollutants between 1990 and 2008, after which time emissions drop off dramatically due to decreased drilling activity associated with the economic downturn and associated lower natural gas prices. Figure 4-6 presents the corresponding statewide drilling activity for comparison. CO emissions show the least variation over time, with the large emission rate improvement associated with the introduction of the Tier 2 emission standards (roughly 50% compared to prior

standards) in the early 2000's offsetting growth in drilling activity during this time. VOC and PM emissions trends are similar to CO, due to similar reductions associated with these same emission standards.

Figure 4-6. Statewide Annual Drilling Rig Activity (000's feet)



NO_x and SO_2 emissions trends display a somewhat different pattern during this time, however. NO_x emissions increase dramatically up through 2008, since the Tier 2 emission standards had a negligible impact on this pollutant, relative to the prior standard. (Substantial NO_x reductions are found with the introduction of the Tier 3 and 4 diesel emission standards, taking effect in the late 2000s and thereafter, however.)

SO_2 emissions are almost solely dependent on diesel fuel sulfur levels, and as long as these levels are constant over time, SO_2 emissions will track drilling activity in a one-to-one fashion. SO_2 emissions are seen to go negligible levels with the introduction of the Tier 4 ultra-low sulfur requirements after 2009. Other emission rates are projected to decrease more slowly as a result of continued penetration of cleaner Tier 3 and 4 engines, coupled with some decline in overall projected drilling activity.

Ozone season day (OSD) emissions were calculated by dividing annual emissions estimates by 365. These values are presented in the tables below. Note that trend charts are not presented for OSD totals, since the relative emissions over time do not change compared to the annual emissions cases above.

Table 4-13. Statewide OSD Emissions Totals (Tons/Day), Controlled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
1990	69.34	8.32	9.48	36.62	6.94	6.73
1993	80.42	8.61	10.79	41.62	7.75	7.52
1996	90.51	11.21	11.08	42.47	7.73	7.50
1999	66.19	4.51	7.59	28.95	4.82	4.68
2000	92.00	6.28	10.40	39.92	6.64	6.44
2001	106.74	7.24	12.08	46.33	7.70	7.47
2002	76.64	5.75	8.10	30.21	5.42	5.26
2003	101.97	7.74	10.42	39.00	6.98	6.77
2004	110.04	8.33	11.09	41.25	7.36	7.14
2005	130.95	9.88	13.12	48.51	8.67	8.41
2006	143.83	11.75	11.33	41.74	6.96	6.75
2007	156.70	2.49	12.17	44.03	6.55	6.36
2008	162.36	2.83	12.58	48.62	7.39	7.16
2009	80.09	1.43	6.03	23.19	3.51	3.41
2010	67.21	0.06	5.06	19.68	2.89	2.81
2011	63.71	0.06	4.73	18.82	2.87	2.78
2012	62.80	0.06	4.70	19.04	2.90	2.82
2013	54.46	0.05	4.62	16.15	1.84	1.79
2014	54.45	0.05	4.63	16.21	1.85	1.79
2015	54.30	0.05	4.64	16.16	1.84	1.79
2016	51.26	0.05	4.63	15.96	1.82	1.76
2017	49.19	0.05	3.88	11.99	1.52	1.47
2018	45.06	0.05	3.19	8.45	1.13	1.10
2019	45.33	0.05	3.21	8.48	1.13	1.10
2020	45.14	0.05	3.22	8.50	1.14	1.10
2021	38.86	0.05	2.28	4.69	0.66	0.64
2022	38.91	0.05	2.29	4.67	0.66	0.64
2023	39.20	0.05	2.31	4.69	0.66	0.64
2024	44.37	0.06	2.62	5.97	0.87	0.84
2025	44.34	0.06	2.62	5.95	0.87	0.84
2026	49.33	0.07	2.83	6.60	0.98	0.95
2027	31.12	0.05	2.00	3.58	0.62	0.60
2028	30.66	0.05	1.99	3.48	0.62	0.60
2029	26.90	0.05	2.16	3.44	0.52	0.51
2030	26.74	0.05	2.15	3.41	0.52	0.50
2031	24.32	0.05	2.13	3.38	0.49	0.47
2032	23.70	0.05	2.11	3.29	0.48	0.46
2033	23.47	0.05	1.84	2.14	0.41	0.39
2034	23.26	0.05	1.82	2.11	0.40	0.39
2035	23.04	0.05	1.81	2.09	0.40	0.38
2036	21.56	0.04	1.75	1.06	0.27	0.26
2037	21.54	0.04	1.75	1.06	0.27	0.26

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2038	21.51	0.04	1.74	1.05	0.27	0.26
2039	20.04	0.04	1.74	1.05	0.27	0.26
2040	20.03	0.04	1.74	1.04	0.27	0.26

Table 4-14. Statewide Annual Emissions Totals (Tons/Year), Uncontrolled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
1990	25,308	3,037	3,462	13,366	2,533	2,457
1993	29,293	3,516	4,029	15,560	2,955	2,866
1996	32,726	3,930	4,522	17,470	3,324	3,224
1999	23,843	2,863	3,291	12,717	2,419	2,347
2000	33,463	4,017	4,611	17,814	3,387	3,285
2001	38,820	4,658	5,311	20,509	3,889	3,772
2002	30,872	3,705	4,233	16,350	3,103	3,010
2003	41,692	5,001	5,679	21,924	4,151	4,026
2004	45,106	5,406	6,081	23,459	4,423	4,291
2005	53,975	6,465	7,230	27,879	5,243	5,086
2006	64,690	7,744	8,592	33,107	6,204	6,018
2007	71,418	8,540	9,341	35,953	6,695	6,494
2008	81,904	9,788	10,638	40,920	7,597	7,369
2009	41,030	4,899	5,271	20,256	3,742	3,630
2010	35,024	4,183	4,502	17,302	3,197	3,101
2011	35,975	4,296	4,620	17,756	3,280	3,182
2012	36,519	4,361	4,689	18,019	3,328	3,228
2013	37,146	4,435	4,767	18,321	3,383	3,282
2014	37,421	4,468	4,803	18,457	3,408	3,306
2015	37,838	4,518	4,855	18,656	3,445	3,341
2016	37,982	4,535	4,873	18,724	3,457	3,353
2017	38,321	4,576	4,916	18,893	3,488	3,384
2018	38,664	4,617	4,960	19,059	3,519	3,413
2019	39,004	4,657	5,002	19,219	3,548	3,441
2020	39,265	4,688	5,034	19,344	3,571	3,463
2021	39,360	4,699	5,044	19,380	3,577	3,469
2022	39,714	4,741	5,087	19,547	3,607	3,499
2023	40,111	4,789	5,136	19,735	3,641	3,532
2024	40,138	4,792	5,139	19,744	3,642	3,533
2025	40,216	4,801	5,148	19,778	3,648	3,539
2026	39,983	4,773	5,117	19,662	3,626	3,518
2027	39,943	4,768	5,112	19,641	3,623	3,514
2028	39,718	4,742	5,083	19,529	3,602	3,494
2029	39,395	4,703	5,041	19,368	3,572	3,465
2030	39,249	4,685	5,022	19,295	3,558	3,452
2031	39,012	4,657	4,992	19,180	3,537	3,431

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2032	38,824	4,635	4,969	19,090	3,521	3,415
2033	38,513	4,598	4,931	18,946	3,495	3,390
2034	38,229	4,564	4,894	18,805	3,469	3,365
2035	37,923	4,528	4,857	18,663	3,443	3,340
2036	37,923	4,528	4,857	18,663	3,443	3,340
2037	37,923	4,528	4,857	18,663	3,443	3,340
2038	37,923	4,528	4,857	18,663	3,443	3,340
2039	37,923	4,528	4,857	18,663	3,443	3,340
2040	37,923	4,528	4,857	18,663	3,443	3,340

Figure 4-7. Statewide Drilling Rig Emissions – Uncontrolled Scenario (NO_x and CO Tons/Year)

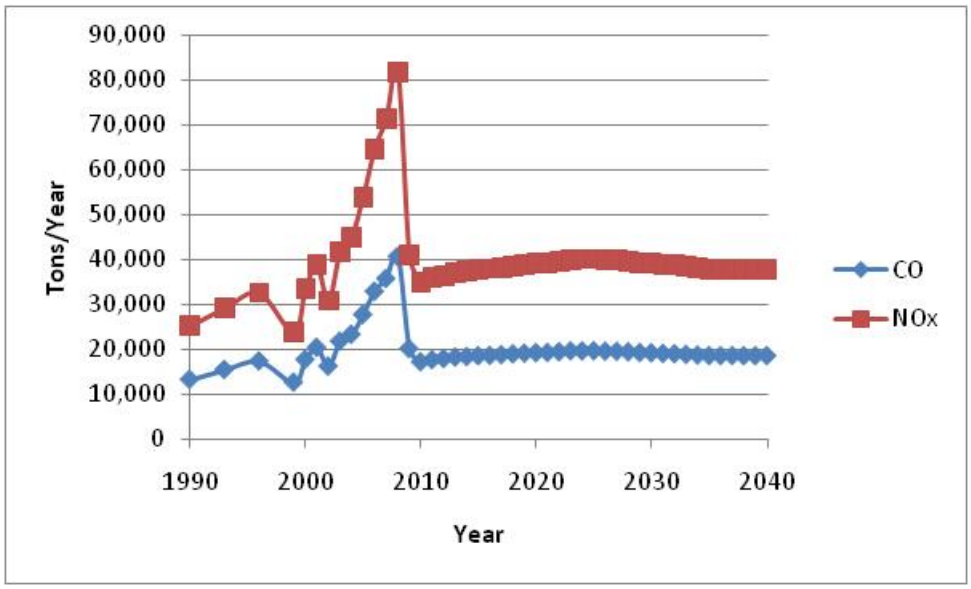


Figure 4-8. Statewide Drilling Rig Emissions – Uncontrolled Scenario (VOC and SO_2 Tons/Year)

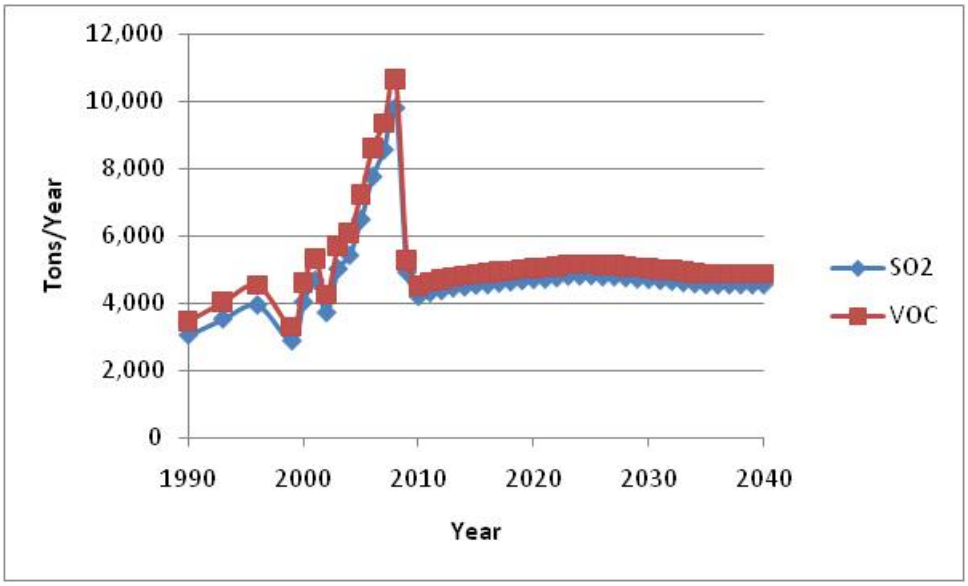
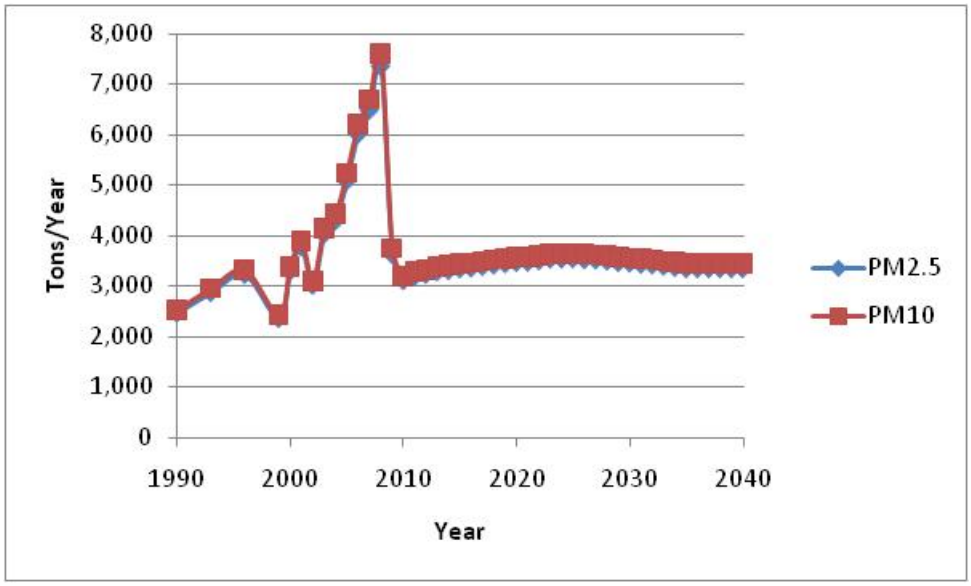


Figure 4-9. Statewide Drilling Rig Emissions – Uncontrolled Scenario (PM_{10} and $PM_{2.5}$ Tons/Year)



The emissions trends presented in Figures 4-7 through 4-9 above clearly show how emissions for all pollutants would be substantially higher without the benefit of the engine and fuel controls implemented since 1990. In addition, since emission rates are held constant for these estimates, the year-to-year changes shown above are exclusively due to changes in historical and projected drilling activity (see Figure 4-6).

Table 4-15. Statewide OSD Emissions Totals (Tons/Day), Uncontrolled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
1990	69.34	8.32	9.48	36.62	6.94	6.73
1993	80.25	9.63	11.04	42.63	8.10	7.85
1996	89.66	10.77	12.39	47.86	9.11	8.83
1999	65.32	7.84	9.02	34.84	6.63	6.43
2000	91.68	11.01	12.63	48.81	9.28	9.00
2001	106.36	12.76	14.55	56.19	10.65	10.33
2002	84.58	10.15	11.60	44.79	8.50	8.25
2003	114.22	13.70	15.56	60.07	11.37	11.03
2004	123.58	14.81	16.66	64.27	12.12	11.75
2005	147.88	17.71	19.81	76.38	14.36	13.93
2006	177.23	21.22	23.54	90.71	17.00	16.49
2007	195.67	23.40	25.59	98.50	18.34	17.79
2008	224.39	26.82	29.14	112.11	20.81	20.19
2009	112.41	13.42	14.44	55.50	10.25	9.95
2010	95.96	11.46	12.33	47.40	8.76	8.50
2011	98.56	11.77	12.66	48.65	8.99	8.72
2012	100.05	11.95	12.85	49.37	9.12	8.84
2013	101.77	12.15	13.06	50.19	9.27	8.99
2014	102.52	12.24	13.16	50.57	9.34	9.06
2015	103.67	12.38	13.30	51.11	9.44	9.15
2016	104.06	12.43	13.35	51.30	9.47	9.19
2017	104.99	12.54	13.47	51.76	9.56	9.27
2018	105.93	12.65	13.59	52.22	9.64	9.35
2019	106.86	12.76	13.70	52.66	9.72	9.43
2020	107.58	12.84	13.79	53.00	9.78	9.49
2021	107.83	12.87	13.82	53.10	9.80	9.50
2022	108.81	12.99	13.94	53.55	9.88	9.59
2023	109.89	13.12	14.07	54.07	9.98	9.68
2024	109.97	13.13	14.08	54.09	9.98	9.68
2025	110.18	13.15	14.10	54.18	9.99	9.69
2026	109.54	13.08	14.02	53.87	9.94	9.64
2027	109.43	13.06	14.01	53.81	9.92	9.63
2028	108.82	12.99	13.93	53.50	9.87	9.57
2029	107.93	12.89	13.81	53.06	9.79	9.49
2030	107.53	12.84	13.76	52.86	9.75	9.46
2031	106.88	12.76	13.68	52.55	9.69	9.40
2032	106.37	12.70	13.61	52.30	9.65	9.36
2033	105.51	12.60	13.51	51.91	9.58	9.29
2034	104.74	12.50	13.41	51.52	9.50	9.22
2035	103.90	12.40	13.31	51.13	9.43	9.15
2036	103.90	12.40	13.31	51.13	9.43	9.15
2037	103.90	12.40	13.31	51.13	9.43	9.15

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2038	103.90	12.40	13.31	51.13	9.43	9.15
2039	103.90	12.40	13.31	51.13	9.43	9.15
2040	103.90	12.40	13.31	51.13	9.43	9.15

Annual county-level NO_x emissions were also investigated for the Controlled scenario for the 2010 base year, in order to help identify the areas of the state with the greatest level of drill rig emissions. Table 4-16 presents these emissions, with counties ranked from highest to lowest. Of the 206 counties with non-zero emissions in 2010, only a small fraction were responsible for a preponderance of total statewide emissions. For example, the top 14 counties were responsible for 50 percent of total NO_x emissions. In addition, 7 of the 14 counties were located in (largely rural) West Texas, with the others being Tarrant, Johnson, Wise, and Denton counties (North Central Texas), Freestone and Panola counties (East Texas), and Webb County (South Texas).

Table 4-16. County NO_x Emissions Totals, Controlled Scenario (2010)

FIPS	County	Tons/Year	Cumulative %
439	Tarrant	1,632.98	6.66%
317	Martin	1,324.56	12.06%
461	Upton	1,273.69	17.25%
383	Reagan	1,164.95	22.00%
251	Johnson	1,047.99	26.27%
135	Ector	1,011.87	30.39%
3	Andrews	980.95	34.39%
329	Midland	721.62	37.33%
479	Webb	694.8	40.17%
497	Wise	514.32	42.26%
173	Glasscock	504.44	44.32%
121	Denton	433.11	46.09%
161	Freestone	433.03	47.85%
365	Panola	421.83	49.57%
165	Gaines	373.75	51.09%
483	Wheeler	370.65	52.60%
371	Pecos	348.75	54.03%
227	Howard	320.98	55.33%
255	Karnes	311.04	56.60%
235	Irion	291.87	57.79%
211	Hemphill	289.36	58.97%
105	Crockett	282.67	60.12%
337	Montague	262.71	61.19%
419	Shelby	259.64	62.25%
475	Ward	236.08	63.22%
283	La Salle	232.37	64.16%
203	Harrison	227.85	65.09%

FIPS	County	Tons/Year	Cumulative %
215	Hidalgo	225.99	66.01%
347	Nacogdoches	222.19	66.92%
505	Zapata	216.28	67.80%
427	Starr	210.66	68.66%
401	Rusk	201.5	69.48%
97	Cooke	200.72	70.30%
357	Ochiltree	188.96	71.07%
413	Schleicher	179.59	71.80%
395	Robertson	177.54	72.52%
389	Reeves	176.32	73.24%
435	Sutton	172.21	73.95%
481	Wharton	172.14	74.65%
123	DeWitt	158.52	75.29%
295	Lipscomb	157.55	75.94%
405	San Augustine	155.09	76.57%
367	Parker	150.98	77.18%
311	McMullen	150.94	77.80%
293	Limestone	145.96	78.39%
391	Refugio	144.86	78.98%
127	Dimmit	143.87	79.57%
47	Brooks	139.06	80.14%
415	Scurry	134.14	80.68%
245	Jefferson	133.87	81.23%
501	Yoakum	131.12	81.76%
115	Dawson	128.3	82.29%
393	Roberts	122.48	82.79%
289	Leon	116.99	83.26%
297	Live Oak	108.8	83.71%
355	Nueces	107.95	84.15%
301	Loving	107.11	84.58%
285	Lavaca	97.93	84.98%
177	Gonzales	94.38	85.37%
261	Kenedy	93.38	85.75%
41	Brazos	90.03	86.12%
431	Sterling	84.69	86.46%
361	Orange	83.33	86.80%
489	Willacy	82.35	87.14%
131	Duval	81.38	87.47%
485	Wichita	76.19	87.78%
221	Hood	74.31	88.08%
199	Hardin	68.64	88.36%
219	Hockley	67.65	88.64%
321	Matagorda	67.39	88.91%
273	Kleberg	66.33	89.18%
457	Tyler	65.94	89.45%

FIPS	County	Tons/Year	Cumulative %
13	Atascosa	65.29	89.72%
239	Jackson	64.66	89.98%
291	Liberty	64.46	90.24%
433	Stonewall	63.89	90.50%
137	Edwards	61.49	90.75%
25	Bee	58.59	90.99%
39	Brazoria	57.6	91.23%
33	Borden	55.83	91.46%
495	Winkler	52.08	91.67%
103	Crane	50.77	91.87%
407	San Jacinto	50.76	92.08%
313	Madison	50.26	92.29%
373	Polk	49.57	92.49%
73	Cherokee	47.28	92.68%
469	Victoria	45.59	92.87%
51	Burleson	44.74	93.05%
71	Chambers	44.6	93.23%
263	Kent	44.02	93.41%
335	Mitchell	44	93.59%
353	Nolan	43.79	93.77%
351	Newton	43.02	93.94%
149	Fayette	40.43	94.11%
175	Goliad	40.32	94.27%
423	Smith	39.27	94.43%
183	Gregg	38.85	94.59%
409	San Patricio	36.96	94.74%
89	Colorado	36.58	94.89%
249	Jim Wells	36.19	95.04%
163	Frio	30.75	95.16%
9	Archer	29.84	95.29%
113	Dallas	29.66	95.41%
185	Grimes	29.19	95.53%
323	Maverick	29.14	95.64%
237	Jack	29.09	95.76%
151	Fisher	27.72	95.88%
493	Wilson	26.57	95.98%
139	Ellis	26.37	96.09%
287	Lee	26.06	96.20%
125	Dickens	25.23	96.30%
429	Stephens	24.78	96.40%
181	Grayson	24.73	96.50%
167	Galveston	24.13	96.60%
207	Haskell	23.33	96.70%
241	Jasper	22.93	96.79%
399	Runnels	22.62	96.88%

FIPS	County	Tons/Year	Cumulative %
169	Garza	21.69	96.97%
443	Terrell	20.9	97.06%
477	Washington	20.61	97.14%
81	Coke	20.57	97.22%
217	Hill	20.45	97.31%
363	Palo Pinto	20.41	97.39%
507	Zavala	19.35	97.47%
107	Crosby	19.25	97.55%
205	Hartley	18.76	97.62%
157	Fort Bend	18.72	97.70%
195	Hansford	18.38	97.78%
417	Shackelford	18.03	97.85%
403	Sabine	17.79	97.92%
503	Young	17.74	97.99%
339	Montgomery	17.63	98.07%
213	Henderson	17.44	98.14%
253	Jones	17.4	98.21%
305	Lynn	16.97	98.28%
201	Harris	16.46	98.34%
15	Austin	15.72	98.41%
57	Calhoun	15.4	98.47%
7	Aransas	15.37	98.53%
499	Wood	15.21	98.60%
451	Tom Green	15.15	98.66%
445	Terry	14.53	98.72%
303	Lubbock	14.12	98.77%
327	Menard	13.94	98.83%
473	Waller	13.57	98.89%
79	Cochran	12.86	98.94%
247	Jim Hogg	11.67	98.99%
459	Upshur	11.44	99.03%
359	Oldham	11.13	99.08%
225	Houston	11.05	99.12%
447	Throckmorton	10.04	99.16%
1	Anderson	9.95	99.20%
487	Wilbarger	9.88	99.24%
315	Marion	9.73	99.28%
331	Milam	9.28	99.32%
83	Coleman	9.22	99.36%
269	King	8.77	99.40%
189	Hale	6.92	99.42%
197	Hardeman	6.85	99.45%
425	Somervell	6.52	99.48%
49	Brown	6.09	99.50%
59	Callahan	6.05	99.53%

FIPS	County	Tons/Year	Cumulative %
341	Moore	6.02	99.55%
95	Concho	5.9	99.58%
61	Cameron	5.87	99.60%
467	Van Zandt	5.86	99.62%
101	Cottle	5.79	99.65%
377	Presidio	5.54	99.67%
159	Franklin	5.29	99.69%
67	Cass	4.73	99.71%
37	Bowie	4.65	99.73%
233	Hutchinson	4.49	99.75%
5	Angelina	4.24	99.77%
379	Rains	3.9	99.78%
77	Clay	3.85	99.80%
223	Hopkins	3.7	99.81%
441	Taylor	3.52	99.83%
63	Camp	3.24	99.84%
275	Knox	3.14	99.85%
187	Guadalupe	3.11	99.87%
155	Foard	2.99	99.88%
325	Medina	2.95	99.89%
35	Bosque	2.88	99.90%
349	Navarro	2.77	99.91%
375	Potter	2.71	99.92%
55	Caldwell	2.59	99.93%
143	Erath	2.43	99.94%
133	Eastland	2.29	99.95%
109	Culberson	2.01	99.96%
279	Lamb	1.86	99.97%
385	Real	1.26	99.97%
23	Baylor	0.92	99.98%
231	Hunt	0.87	99.98%
307	McCulloch	0.8	99.99%
93	Comanche	0.8	99.99%
257	Kaufman	0.59	99.99%
179	Gray	0.46	99.99%
421	Sherman	0.44	99.99%
471	Walker	0.34	100.00%
411	San Saba	0.27	100.00%
193	Hamilton	0.2	100.00%
21	Bastrop	0.19	100.00%
145	Falls	0.16	100.00%
29	Bexar	0.09	100.00%
281	Lampasas	0.05	100.00%
309	McLennan	0.04	100.00%

Trends in annual NO_x emissions were plotted for the top 10 counties for the entire analysis period, as shown below in Figure 4-10. While there is some relative variation in historical estimates, most county trends follow the general pattern seen in the statewide totals (see Figure 4-3).Figures 4-11, 4-12, and 4-13 display the county-level distribution of annual NO_x, VOC, and $PM_{2.5}$ emissions for the 2010 base year.

Figure 4-10. Annual NO_x Emissions by Year – Top 10 Counties (2010 basis)

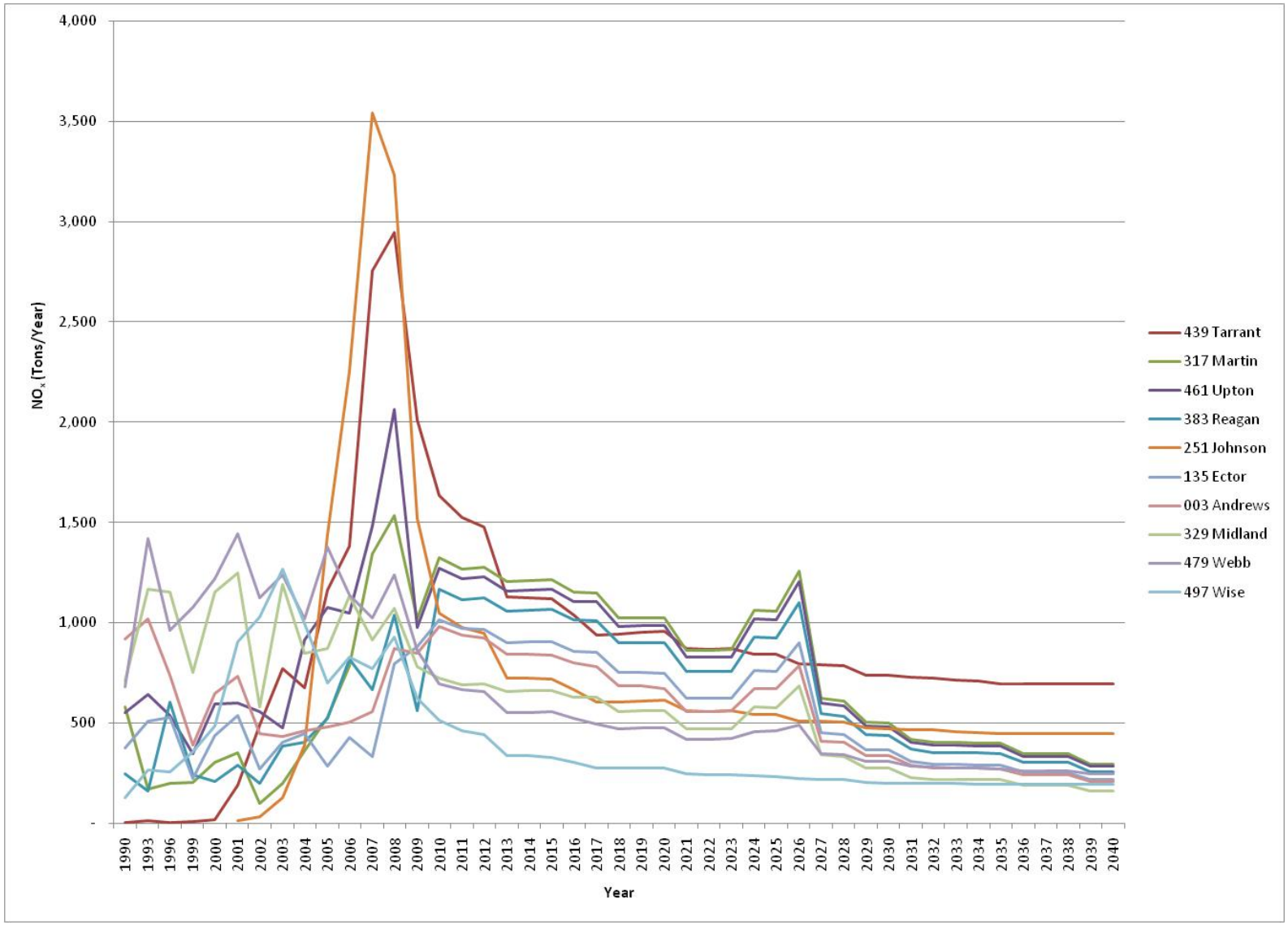


Figure 4-11. 2010 Annual NO_x Emissions by County (Tons/Year)

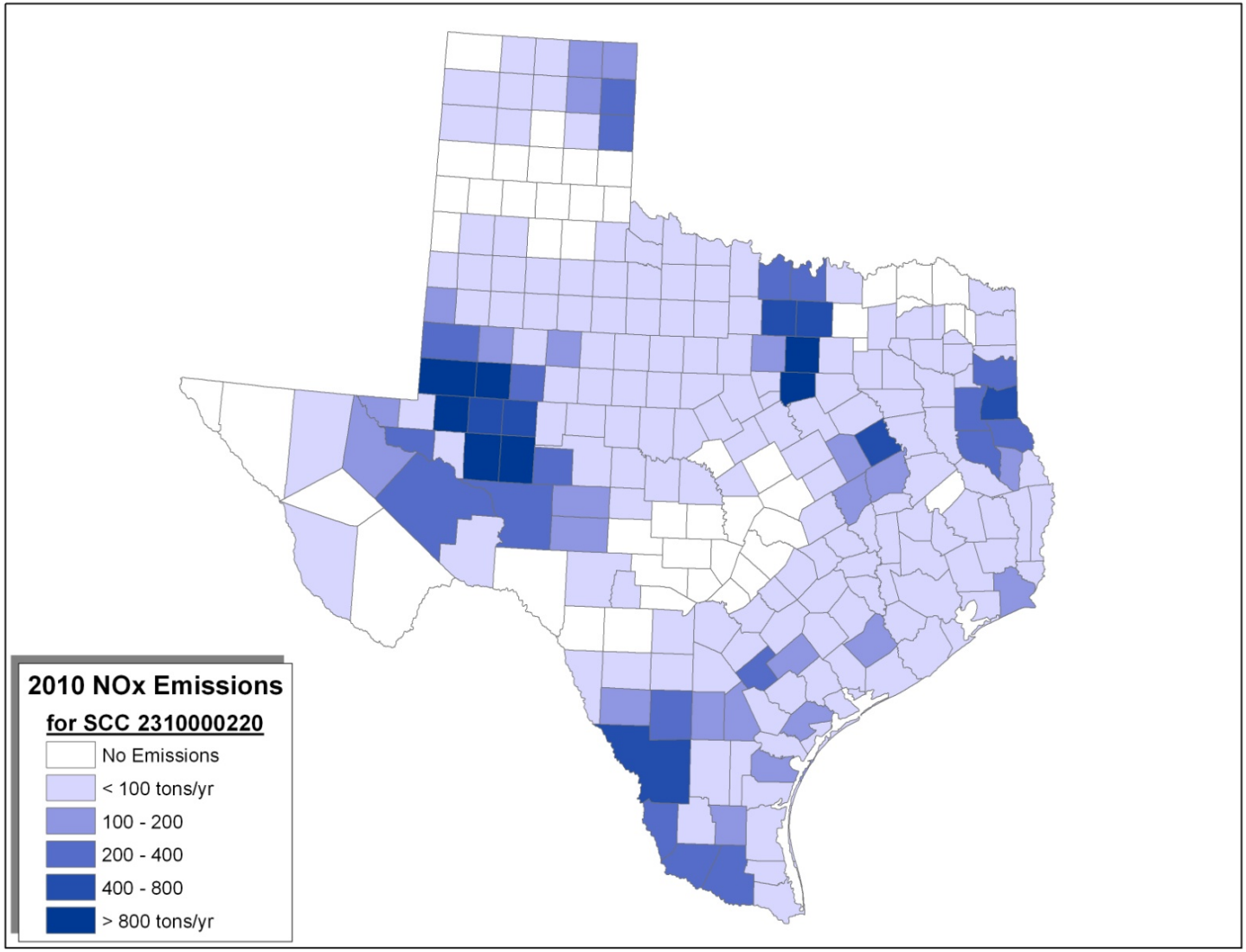


Figure 4-12. 2010 Annual VOC Emissions by County (Tons/Year)

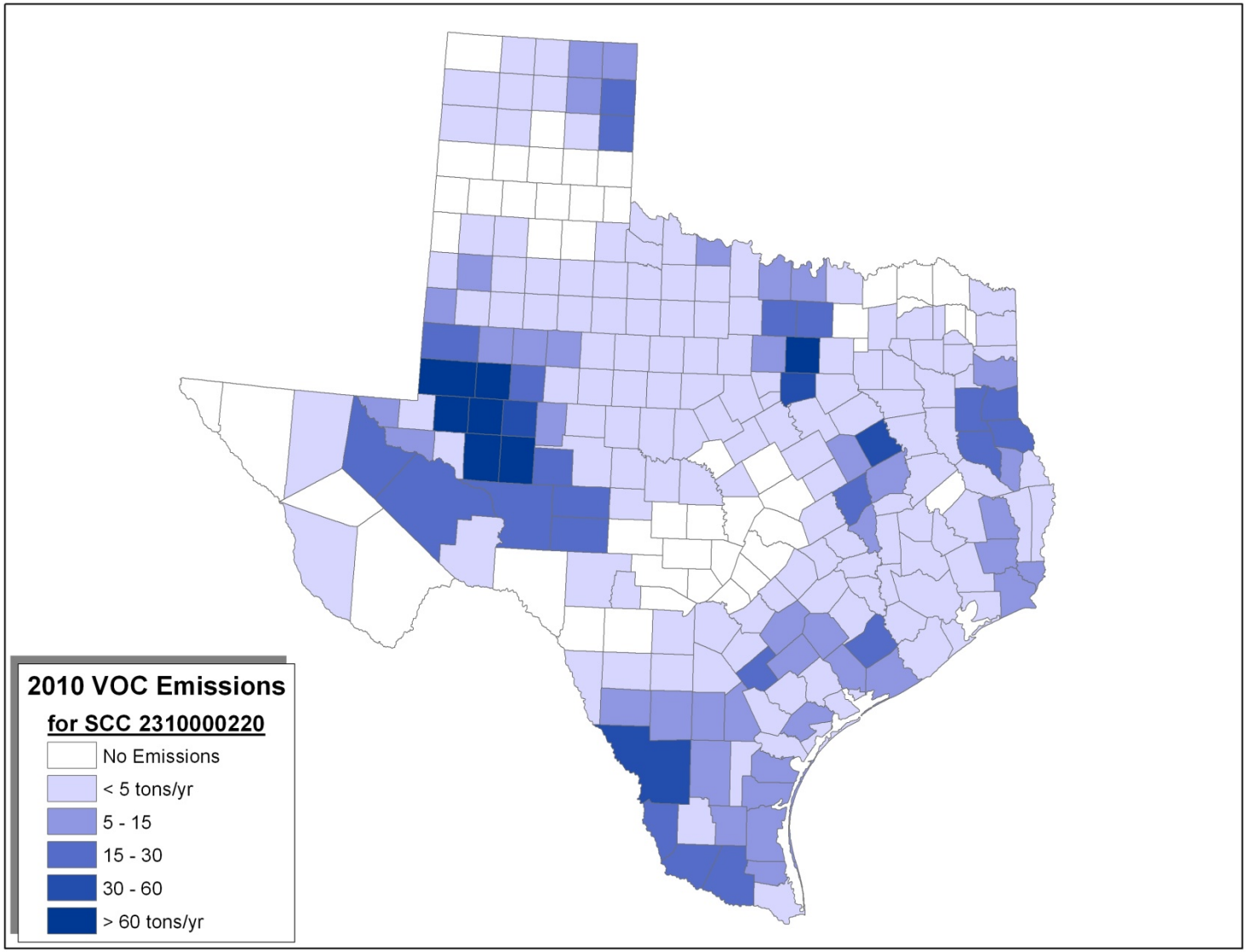
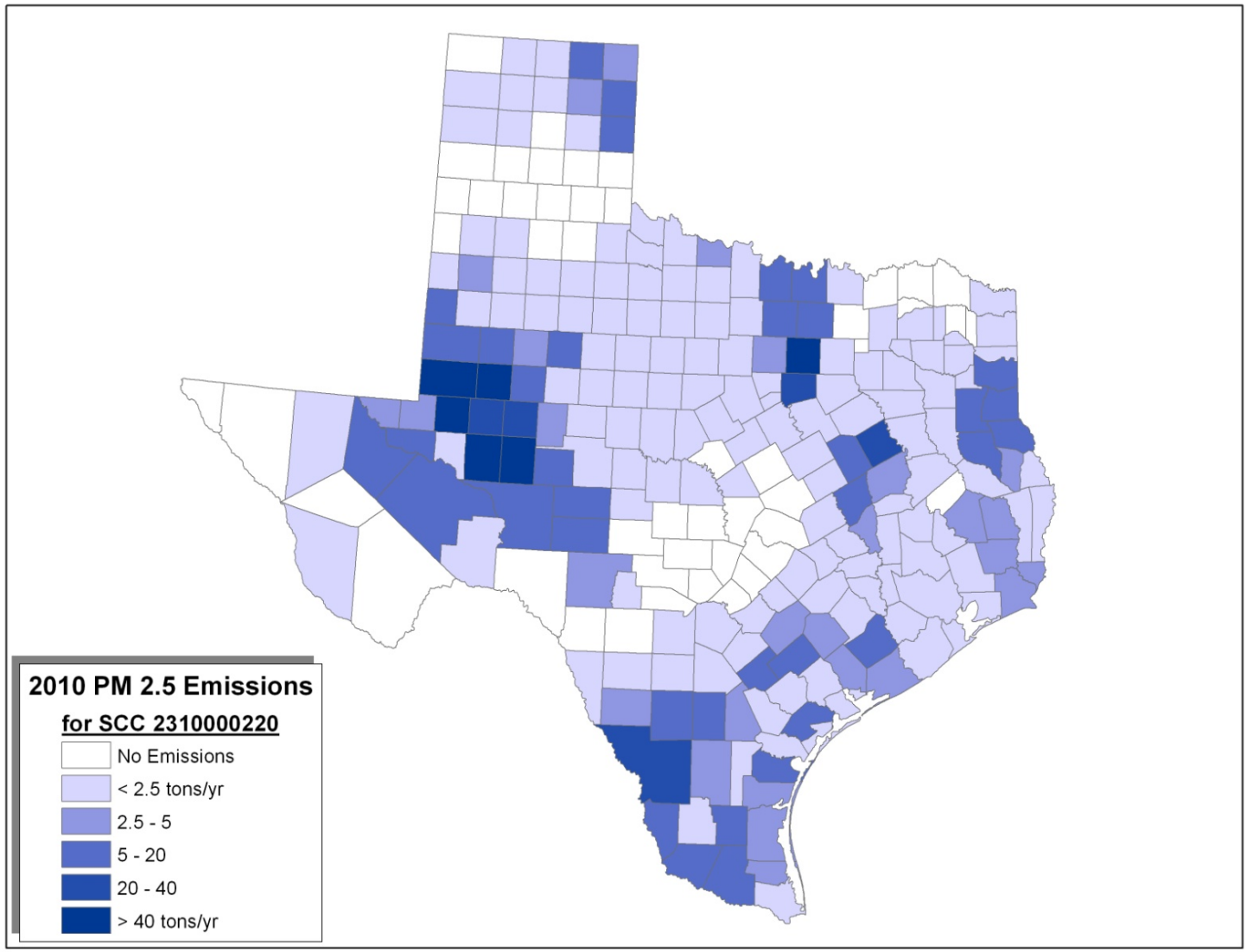


Figure 4-13. 2010 Annual $PM_{2.5}$ Emissions by County (Tons/Year)



4.4.2 CERS XML Files

Once the emissions inventories were completed, CERS XML-formatted input files were prepared. For purposes of XML preparation, SCC 23-10-000-220 (Industrial Processes - Oil and Gas Exploration and Production - All Processes - Drill Rigs) was used, consistent with the 2009 study. ERG uploaded the CERS XML files to the TexAER test server to ensure the files were complete and accurate and in a format consistent with the TexAER area source file data requirements.

4.5 Quality Assurance

ERG conducted a variety of quality assurance checks consistent with the requirements of the Quality Assurance Project Plan (QAPP) submitted to the TCEQ for this effort. Key spreadsheet inputs and calculations used to estimate emissions were checked to ensure accuracy, and final emission estimates were evaluated for internal and external consistency, as described in detail in Drill Rig QA-QC_1.xlsx, submitted to the TCEQ as part of deliverable 2.2 of this effort. Errors identified during the QA were resolved and emissions estimates were subsequently revised prior to generation of the final XML files developed for TexAER.

The quality assurance tracking spreadsheet referred to above was broken into several components, each intended to evaluate different aspects of the study calculations. First, basic calculations were checked in ERG's working files, in order to identify potential errors in worksheet equations and data table inputs. Individual steps in the calculation QA process are listed separately, noting the goal of each QA check, how the check was performed, and the outcome of the check. If a check found an error, the correction result was also documented. A second set of QA checks were performed on the emissions inventory results themselves to help ensure consistency with expected results and the reasonableness of projection trends. Quantitative comparisons were made the with 2008 base year inventory results from the previous study, as well as more qualitative evaluations of emissions trends in relation to projected activity and the effectiveness the various engine and fuel controls being phased in over time. The following highlights some of the key findings from this analysis.

Key findings from the evaluation of final emission estimates include the following. First, the time series charts generated for the pollutants appear to follow a reasonable trend for future year projections, with significant activity and emissions drop offs occurring between 2008 and 2009. The differences in trends across pollutants appear to be explained by the differential impact of emission control phase-in schedules, as discussed in Section 4.4.1 above.

The results from the current study were also compared against the 2008 base year findings from the previous study, as summarized in Table 4-17.

Table 4-17. Comparison of Statewide 2008 Annual Emissions Totals (Tons/Year), Current and Previous Studies, Controlled Scenario

Year	Study	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
2008	Previous	16,721	55,238	2,543	2,467	956	4,326
2008	Current	17,745	59,261	2,696	2,615	1,033	4,593
2008	% Diff	6.1%	7.3%	6.0%	6.0%	8.0%	6.2%

As seen in the table, the 2008 criteria pollutant emissions were found to be between 6 and 8 percent higher in current emission inventory than in 2009 study. The ERG staff responsible for processing the TRC data confirmed that an enhanced methodology was adopted for the current study to include additional drilling activity that was not included in the 2009 effort. This resulted in an increase of 8 percent in the statewide drill depth totals (163,348 v. 151,204). Since drill depth increases were not distributed uniformly across counties or well types (which have different emission factors), the resulting emission impact generally did not increase on a one-to-one basis with activity. However, as SO_2 emissions do in fact vary on a 1:1 basis with activity, independent of engine model year and emission standard, we see a precise match for this pollutant with activity (8 percent as expected).

Finally, trend graphs were generated to compare the difference between controlled and uncontrolled emissions scenarios (see Figures 4-14 through 4-18). As noted above, 1990 emission rates were used to represent the uncontrolled case for all scenario years. Controlled and uncontrolled emissions are shown in the following figures over the entire scenario year range.

Figure 4-14. Controlled and Uncontrolled Emissions Projections (NO_x Tons/Year)

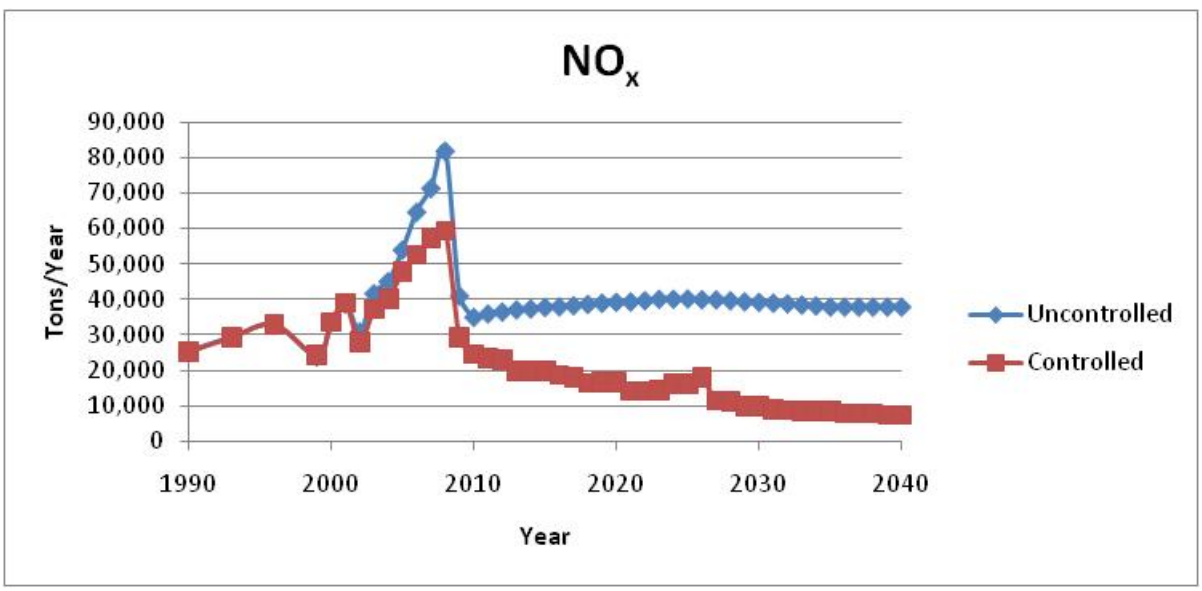


Figure 4-15. Controlled and Uncontrolled Emissions Projections (CO Tons/Year)

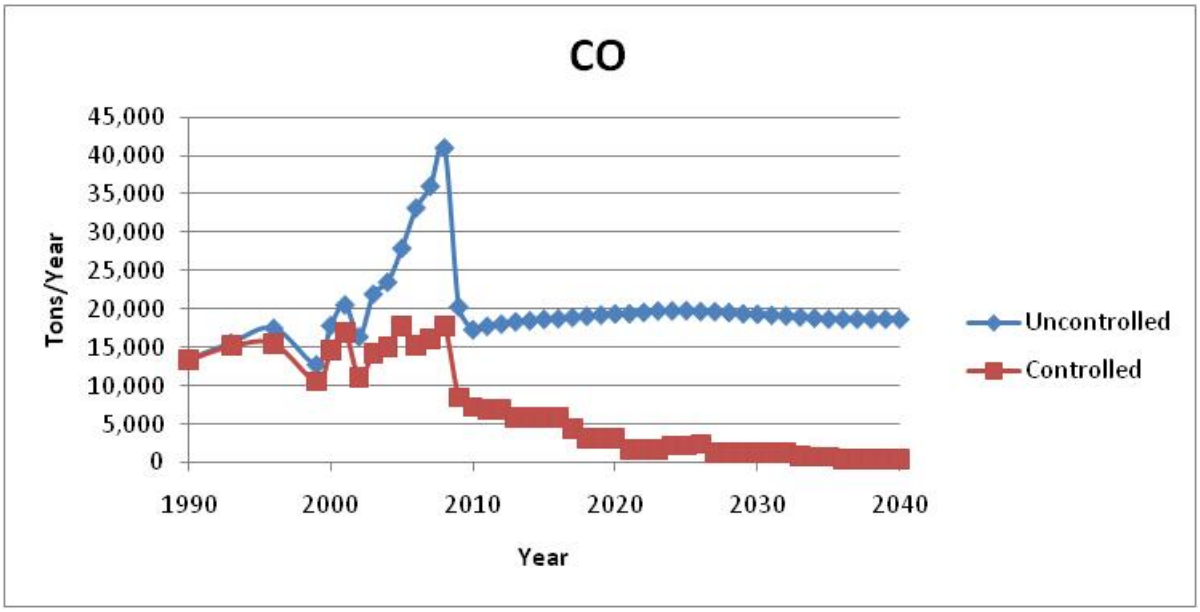


Figure 4-16. Controlled and Uncontrolled Emissions Projections (VOC Tons/Year)

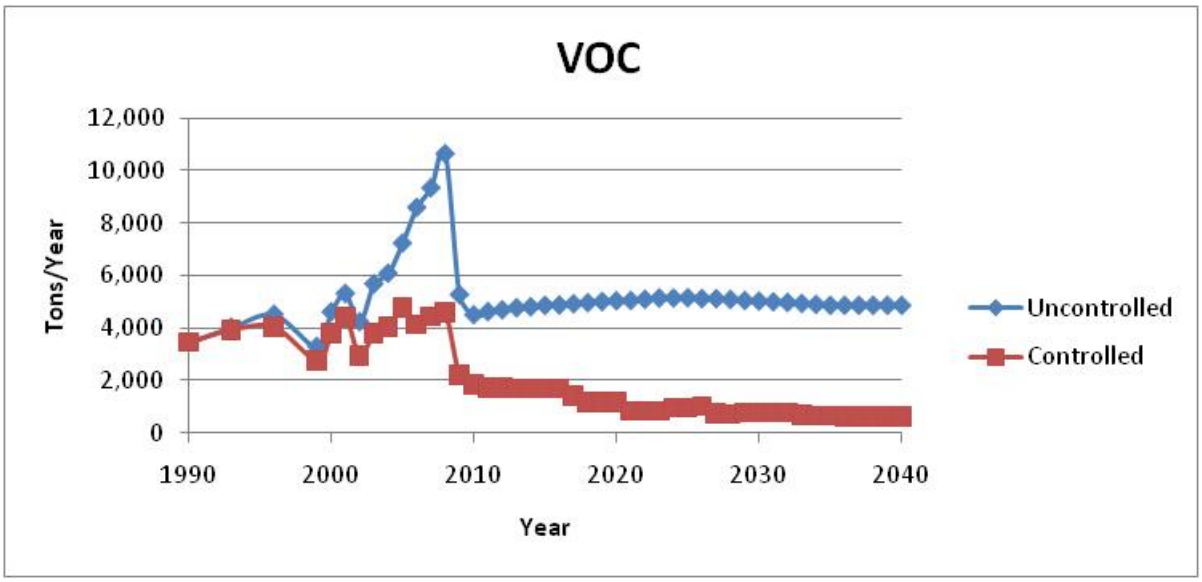


Figure 4-17. Controlled and Uncontrolled Emissions Projections (PM_{10} Tons/Year)

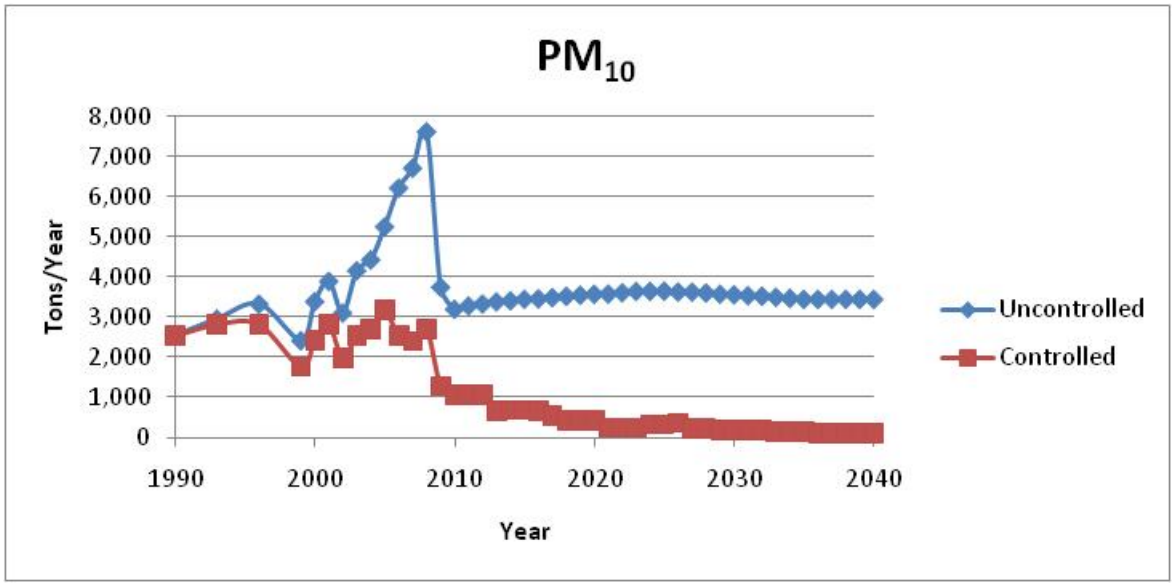
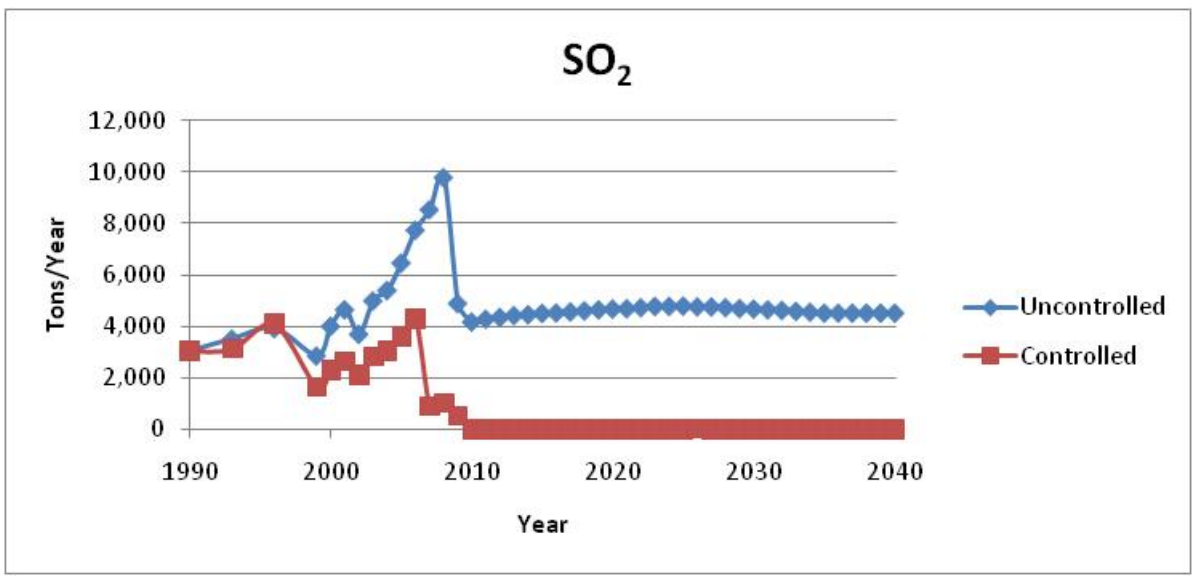


Figure 4-18. Controlled and Uncontrolled Emissions Projections (SO_2 Tons/Year)



The difference between the controlled and uncontrolled emissions deviate more and more over time, as expected. The NO_x deviation shown above is not significant until substantial penetration of Tier 3+ emission standards in the late 2000's. The emissions benefit is more pronounced earlier for CO, VOC, and PM due to the greater benefit of the Tier 2 emission standards in the early 2000's, as discussed above in Section 4.4.1. SO_2 deviation shows the most abrupt increase (in 2010 when ultra-low diesel sulfur

regulations are enacted), since emissions for this pollutant depends on fuel sulfur changes alone, as opposed to fleet turnover.

5. Conclusions and Recommendations

This study presents comprehensive, statewide emissions inventories for Texas for drilling rig engines. These inventories were prepared using well drilling activity data obtained through permit records from the TRC, combined with emissions data derived through detailed drilling rig engine data collected through a bottom-up survey effort conducted for the 2009 study. The study represents a significant improvement upon the 2009 effort, utilizing improved gap filling methods for the TRC dataset to obtain a more complete and accurate set of drill rig activity. In addition, this study utilized historical drilling data from the TRC to estimate past emissions, rather than relying on surrogate based back-casting from a base year, as was done in the previous study. Finally, the study greatly expanded the time horizon of the previous study, ranging from 1990 with projections through 2040. The result is a reliable, temporally resolved profile of county-level drilling activity emissions. The successful update of the TexAER system with this data, associated with a new area source SCC, will allow for improved SIP and trend analysis for all regions of the state.

Based on the projected oil and gas production levels in Texas from the EIA, drilling activity is estimated to remain relatively constant across the state from 2011 through 2035. However, the continued phase-in of more stringent Non-Road diesel engine emission standards should cause a steady decrease in drilling-related emissions over time. SO_2 emissions levels in particular are estimated to have fallen precipitously due to the introduction of the ultra-low sulfur standards for diesel fuel in 2010, and should remain extremely low for the foreseeable future.

An analysis of county-level data found that the vast majority of Texas counties produced some level of emissions associated with drilling activities (206 of 254 counties) in the 2010 base year. However, the county-level distribution of NO_x emissions is highly skewed, with 14 counties being responsible for 50 percent of total statewide NO_x in 2010. In addition, the preponderance of the high NO_x emitting counties were predominantly in West and North-Central Texas.

While the emissions inventory results provide an excellent basis for assessing historical emissions levels, significant sources of uncertainty remain. Most importantly, projections of future activity are highly uncertain, subject to significant rises and falls depending upon economic factors and associated oil and gas prices. Accordingly, periodic refinement of the activity data used for projected years 2011 through 2040 is strongly recommended to account for such factors. In addition, the contribution of fracturing operations to drilling activity emissions remains unknown at this time. Given that fracturing activities occur at the end of the completion phase, that the engines involved are brought in after the removal of the main drilling equipment, and that

fracturing may recur in the future at undetermined intervals to re-invigorate flows, fracturing emissions may merit a new SCC to facilitate future inventory development.

6. References

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Appendix A. Annual HAP Emissions by Species (lbs/yr)

Annual PM Toxics by Year (Lbs/Year)

Year	Antimony	Arsenic	Cadmium	Cobalt	Chlorine	Lead	Manganese	Nickel	Mercury	Phosphorous	Selenium
1990	182.41	25.33	202.68	55.74	1743.01	212.81	202.68	96.27	152.01	643.50	50.67
1993	203.64	28.28	226.26	62.22	1945.86	237.58	226.26	107.48	169.70	718.39	56.57
1996	203.17	28.22	225.74	62.08	1941.39	237.03	225.74	107.23	169.31	716.73	56.44
1999	126.70	17.60	140.77	38.71	1210.66	147.81	140.77	66.87	105.58	446.96	35.19
2000	174.42	24.22	193.80	53.29	1666.65	203.49	193.80	92.05	145.35	615.30	48.45
2001	202.32	28.10	224.80	61.82	1933.31	236.04	224.80	106.78	168.60	713.75	56.20
2002	142.43	19.78	158.25	43.52	1360.98	166.17	158.25	75.17	118.69	502.46	39.56
2003	183.43	25.48	203.81	56.05	1752.78	214.00	203.81	96.81	152.86	647.10	50.95
2004	193.52	26.88	215.02	59.13	1849.17	225.77	215.02	102.13	161.26	682.69	53.75
2005	227.76	31.63	253.07	69.59	2176.38	265.72	253.07	120.21	189.80	803.49	63.27
2006	182.80	25.39	203.11	55.86	1746.76	213.27	203.11	96.48	152.33	644.88	50.78
2007	172.21	23.92	191.34	52.62	1645.53	200.91	191.34	90.89	143.51	607.51	47.84
2008	194.09	26.96	215.65	59.30	1854.60	226.43	215.65	102.43	161.74	684.69	53.91
2009	92.33	12.82	102.59	28.21	882.26	107.72	102.59	48.73	76.94	325.72	25.65
2010	76.00	10.56	84.44	23.22	726.21	88.67	84.44	40.11	63.33	268.11	21.11
2011	75.39	10.47	83.77	23.04	720.39	87.95	83.77	39.79	62.82	265.96	20.94
2012	76.32	10.60	84.80	23.32	729.30	89.04	84.80	40.28	63.60	269.25	21.20
2013	48.37	6.72	53.75	14.78	462.23	56.43	53.75	25.53	40.31	170.65	13.44
2014	48.60	6.75	54.00	14.85	464.36	56.70	54.00	25.65	40.50	171.44	13.50
2015	48.46	6.73	53.85	14.81	463.10	56.54	53.85	25.58	40.39	170.97	13.46
2016	47.75	6.63	53.05	14.59	456.26	55.71	53.05	25.20	39.79	168.45	13.26
2017	39.83	5.53	44.25	12.17	380.56	46.46	44.25	21.02	33.19	140.50	11.06
2018	29.70	4.13	33.00	9.08	283.81	34.65	33.00	15.68	24.75	104.78	8.25
2019	29.80	4.14	33.12	9.11	284.80	34.77	33.12	15.73	24.84	105.14	8.28
2020	29.87	4.15	33.18	9.13	285.39	34.84	33.18	15.76	24.89	105.36	8.30
2021	17.29	2.40	19.21	5.28	165.18	20.17	19.21	9.12	14.41	60.98	4.80
2022	17.31	2.40	19.24	5.29	165.44	20.20	19.24	9.14	14.43	61.08	4.81
2023	17.39	2.42	19.32	5.31	166.17	20.29	19.32	9.18	14.49	61.35	4.83
2024	22.87	3.18	25.41	6.99	218.51	26.68	25.41	12.07	19.06	80.67	6.35
2025	22.80	3.17	25.34	6.97	217.88	26.60	25.34	12.03	19.00	80.44	6.33

Year	Antimony	Arsenic	Cadmium	Cobalt	Chlorine	Lead	Manganese	Nickel	Mercury	Phosphorous	Selenium
2026	25.69	3.57	28.55	7.85	245.50	29.97	28.55	13.56	21.41	90.63	7.14
2027	16.39	2.28	18.21	5.01	156.59	19.12	18.21	8.65	13.66	57.81	4.55
2028	16.25	2.26	18.06	4.97	155.28	18.96	18.06	8.58	13.54	57.33	4.51
2029	13.71	1.90	15.24	4.19	131.05	16.00	15.24	7.24	11.43	48.38	3.81
2030	13.61	1.89	15.12	4.16	130.03	15.88	15.12	7.18	11.34	48.01	3.78
2031	12.76	1.77	14.17	3.90	121.90	14.88	14.17	6.73	10.63	45.00	3.54
2032	12.59	1.75	13.99	3.85	120.34	14.69	13.99	6.65	10.49	44.43	3.50
2033	10.65	1.48	11.83	3.25	101.76	12.42	11.83	5.62	8.87	37.57	2.96
2034	10.53	1.46	11.70	3.22	100.65	12.29	11.70	5.56	8.78	37.16	2.93
2035	10.42	1.45	11.58	3.19	99.61	12.16	11.58	5.50	8.69	36.77	2.90
2036	7.16	0.99	7.96	2.19	68.41	8.35	7.96	3.78	5.97	25.26	1.99
2037	7.14	0.99	7.94	2.18	68.25	8.33	7.94	3.77	5.95	25.20	1.98
2038	7.13	0.99	7.92	2.18	68.12	8.32	7.92	3.76	5.94	25.15	1.98
2039	7.12	0.99	7.91	2.17	68.00	8.30	7.91	3.76	5.93	25.11	1.98
2040	7.11	0.99	7.90	2.17	67.90	8.29	7.90	3.75	5.92	25.07	1.97

Annual TOG Toxics by Year (Lbs/Year)

Year	1,3-Butadiene	N-Hexane	2,2,4-Trimethylpentane	Methylalcohol	Formaldehyde	Acetaldehyde	Propionaldehyde
1990	13,364	11,253	21,100	2,110	1,034,618	516,958	68,224
1993	15,209	12,808	24,015	2,401	1,177,514	588,357	77,647
1996	15,613	13,147	24,651	2,465	1,208,736	603,957	79,706
1999	10,688	9,001	16,876	1,688	827,484	413,461	54,566
2000	14,659	12,345	23,146	2,315	1,134,927	567,078	74,839
2001	17,024	14,336	26,880	2,688	1,318,011	658,557	86,912
2002	11,408	9,606	18,012	1,801	883,187	441,293	58,239
2003	14,679	12,362	23,178	2,318	1,136,492	567,860	74,942
2004	15,624	13,157	24,669	2,467	1,209,603	604,390	79,763
2005	18,485	15,566	29,186	2,919	1,431,093	715,060	94,368
2006	15,961	13,441	25,202	2,520	1,235,748	617,454	81,487
2007	17,150	14,442	27,079	2,708	1,327,782	663,440	87,556
2008	17,731	14,932	27,997	2,800	1,372,789	685,928	90,524
2009	8,501	7,159	13,423	1,342	658,177	328,865	43,401
2010	7,126	6,001	11,252	1,125	551,700	275,662	36,380
2011	6,660	5,609	10,517	1,052	515,663	257,656	34,004
2012	6,625	5,579	10,460	1,046	512,899	256,275	33,821
2013	6,513	5,484	10,283	1,028	504,212	251,935	33,248
2014	6,530	5,499	10,310	1,031	505,551	252,604	33,337
2015	6,536	5,504	10,320	1,032	506,013	252,834	33,367
2016	6,526	5,496	10,305	1,030	505,288	252,472	33,319
2017	5,470	4,606	8,636	864	423,469	211,591	27,924
2018	4,492	3,783	7,093	709	347,781	173,772	22,933
2019	4,518	3,804	7,133	713	349,773	174,768	23,065
2020	4,536	3,820	7,163	716	351,213	175,487	23,160
2021	3,212	2,705	5,072	507	248,707	124,269	16,400
2022	3,231	2,721	5,102	510	250,154	124,992	16,496
2023	3,256	2,742	5,142	514	252,116	125,972	16,625
2024	3,692	3,109	5,829	583	285,839	142,822	18,849
2025	3,692	3,109	5,829	583	285,805	142,806	18,846

Year	1,3-Butadiene	N-Hexane	2,2,4-Trimethylpentane	Methylalcohol	Formaldehyde	Acetaldehyde	Propionaldehyde
2026	3,985	3,355	6,291	629	308,487	154,139	20,342
2027	2,824	2,378	4,460	446	218,673	109,262	14,420
2028	2,799	2,357	4,419	442	216,685	108,269	14,289
2029	3,038	2,558	4,796	480	235,173	117,507	15,508
2030	3,023	2,546	4,773	477	234,057	116,949	15,434
2031	3,003	2,528	4,741	474	232,461	116,152	15,329
2032	2,980	2,510	4,705	471	230,720	115,282	15,214
2033	2,591	2,181	4,090	409	200,561	100,212	13,225
2034	2,569	2,164	4,057	406	198,932	99,398	13,118
2035	2,548	2,145	4,023	402	197,242	98,554	13,006
2036	2,461	2,073	3,886	389	190,551	95,211	12,565
2037	2,460	2,072	3,885	388	190,471	95,171	12,560
2038	2,459	2,071	3,883	388	190,404	95,138	12,556
2039	2,459	2,070	3,882	388	190,347	95,109	12,552
2040	2,458	2,070	3,881	388	190,299	95,085	12,549

Year	Benzene	Toluene	Ethylbenzene	O-Xylene	M-Xylene	P-Xylene	Styrene	Isopropylbenzene(Cumene)	Naphthalene
1990	140,669	103,392	21,804	23,914	42,904	7,033	4,220	1,407	6,330
1993	160,097	117,671	24,815	27,216	48,830	8,005	4,803	1,601	7,204
1996	164,342	120,791	25,473	27,938	50,124	8,217	4,930	1,643	7,395
1999	112,506	82,692	17,438	19,126	34,314	5,625	3,375	1,125	5,063
2000	154,307	113,416	23,918	26,232	47,064	7,715	4,629	1,543	6,944
2001	179,199	131,711	27,776	30,464	54,656	8,960	5,376	1,792	8,064
2002	120,080	88,259	18,612	20,414	36,624	6,004	3,602	1,201	5,404
2003	154,520	113,572	23,951	26,268	47,128	7,726	4,636	1,545	6,953
2004	164,460	120,878	25,491	27,958	50,160	8,223	4,934	1,645	7,401
2005	194,574	143,012	30,159	33,078	59,345	9,729	5,837	1,946	8,756
2006	168,015	123,491	26,042	28,562	51,244	8,401	5,040	1,680	7,561
2007	180,528	132,688	27,982	30,690	55,061	9,026	5,416	1,805	8,124
2008	186,647	137,186	28,930	31,730	56,927	9,332	5,599	1,866	8,399
2009	89,487	65,773	13,870	15,213	27,294	4,474	2,685	895	4,027

Year	Benzene	Toluene	Ethylbenzene	O-Xylene	M-Xylene	P-Xylene	Styrene	Isopropylbenzene(Cumene)	Naphthalene
2010	75,010	55,132	11,627	12,752	22,878	3,751	2,250	750	3,375
2011	70,110	51,531	10,867	11,919	21,384	3,506	2,103	701	3,155
2012	69,735	51,255	10,809	11,855	21,269	3,487	2,092	697	3,138
2013	68,554	50,387	10,626	11,654	20,909	3,428	2,057	686	3,085
2014	68,736	50,521	10,654	11,685	20,964	3,437	2,062	687	3,093
2015	68,798	50,567	10,664	11,696	20,984	3,440	2,064	688	3,096
2016	68,700	50,494	10,648	11,679	20,953	3,435	2,061	687	3,091
2017	57,576	42,318	8,924	9,788	17,561	2,879	1,727	576	2,591
2018	47,285	34,754	7,329	8,038	14,422	2,364	1,419	473	2,128
2019	47,556	34,954	7,371	8,084	14,505	2,378	1,427	476	2,140
2020	47,752	35,097	7,402	8,118	14,564	2,388	1,433	478	2,149
2021	33,815	24,854	5,241	5,748	10,313	1,691	1,014	338	1,522
2022	34,011	24,998	5,272	5,782	10,373	1,701	1,020	340	1,531
2023	34,278	25,194	5,313	5,827	10,455	1,714	1,028	343	1,543
2024	38,863	28,564	6,024	6,607	11,853	1,943	1,166	389	1,749
2025	38,859	28,561	6,023	6,606	11,852	1,943	1,166	389	1,749
2026	41,942	30,828	6,501	7,130	12,792	2,097	1,258	419	1,887
2027	29,731	21,852	4,608	5,054	9,068	1,487	892	297	1,338
2028	29,461	21,654	4,566	5,008	8,986	1,473	884	295	1,326
2029	31,975	23,501	4,956	5,436	9,752	1,599	959	320	1,439
2030	31,823	23,390	4,933	5,410	9,706	1,591	955	318	1,432
2031	31,606	23,230	4,899	5,373	9,640	1,580	948	316	1,422
2032	31,369	23,056	4,862	5,333	9,568	1,568	941	314	1,412
2033	27,269	20,042	4,227	4,636	8,317	1,363	818	273	1,227
2034	27,047	19,880	4,192	4,598	8,249	1,352	811	270	1,217
2035	26,817	19,711	4,157	4,559	8,179	1,341	805	268	1,207
2036	25,908	19,042	4,016	4,404	7,902	1,295	777	259	1,166
2037	25,897	19,034	4,014	4,402	7,899	1,295	777	259	1,165
2038	25,888	19,028	4,013	4,401	7,896	1,294	777	259	1,165
2039	25,880	19,022	4,011	4,400	7,893	1,294	776	259	1,165
2040	25,873	19,017	4,010	4,398	7,891	1,294	776	259	1,164

Appendix B. Texas County Groupings Used for Growth Factor Projection Assignment

Midcontinent = District 10	
County	**TRC Distr.**
Armstrong	10
Briscoe	10
Carson	10
Castro	10
Childress	10
Collingsworth	10
Dallam	10
Deaf Smith	10
Donley	10
Gray	10
Hall	10
Hansford	10
Hartley	10
Hemphill	10
Hutchinson	10
Lipscomb	10
Moore	10
Ochiltree	10
Oldham	10
Parmer	10
Potter	10
Randall	10
Roberts	10
Sherman	10
Swisher	10
Wheeler	10

Southwest = Districts 7b, 7c, 8, 8a, 9	
County	**TRC Distr.**
Andrews	8
Archer	9
Bailey	8A
Baylor	9
Borden	8A
Brewster	8
Brown	7B
Callahan	7B
Clay	9
Cochran	8A
Coke	7C
Coleman	7B
Comanche	7B

Southwest = Districts 7b, 7c, 8, 8a, 9	
County	**TRC Distr.**
Concho	7C
Cooke	9
Coryell	7B
Cottle	8A
Crane	8
Crockett	7C
Crosby	8A
Culberson	8
Dawson	8A
Denton	9
Dickens	8A
Eastland	7B
Ector	8
El Paso	8
Erath	7B
Fisher	7B
Floyd	8A
Foard	9
Gaines	8A
Garza	8A
Glasscock	8
Grayson	9
Hale	8A
Hamilton	7B
Hardeman	9
Haskell	7B
Hockley	8A
Hood	7B
Howard	8
Hudspeth	8
Irion	7C
Jack	9
Jeff Davis	8
Jones	7B
Kent	8A
Kimble	7C
King	8A
Knox	9
Lamb	8A
Lampasas	7B
Loving	8
Lubbock	8A
Lynn	8A
McCulloch	7C

Southwest = Districts 7b, 7c, 8, 8a, 9	
County	**TRC Distr.**
Martin	8
Menard	7C
Midland	8
Mills	7B
Mitchell	8
Montague	9
Motley	8A
Nolan	7B
Palo Pinto	7B
Parker	7B
Pecos	8
Presidio	8
Reagan	7C
Reeves	8
Runnels	7C
San Saba	7B
Schleicher	7C
Scurry	8A
Schackelford	7B
Somervell	7B
Stephens	7B
Sterling	8
Stonewall	7B
Sutton	7C
Taylor	7B
Terrell	7C
Terry	8A
Throckmorton	7B
Tom Green	7C
Upton	7C
Ward	8
Wichita	9
Wilbarger	9
Winkler	8
Wise	9
Yoakum	8A
Young	9

Gulf Coast = All other Districts	
County	**TRC Distr.**
Anderson	6
Angelina	6
Aransas	4
Atascosa	1

Gulf Coast = All other Districts	
County	**TRC Distr.**
Austin	3
Bandera	1
Bastrop	1
Bee	2
Bell	1
Bexar	1
Blanco	1
Bosque	5
Bowie	6
Brazoria	3
Brazos	3
Brooks	4
Burleson	3
Burnet	1
Caldwell	1
Calhoun	2
Cameron	4
Camp	6
Cass	6
Chambers	3
Cherokee	6
Collin	5
Colorado	3
Comal	1
Dallas	5
Delta	5
De Witt	2
Dimmit	1
Duval	4
Edwards	1
Ellis	5
Falls	5
Fannin	5
Fayette	3
Fort Bend	3
Franklin	6
Freestone	5
Frio	1
Galveston	3
Gillespie	1
Goliad	2
Gonzales	1
Gregg	6
Grimes	3

Gulf Coast = All other Districts	
County	**TRC Distr.**
Guadalupe	1
Hardin	3
Harris	3
Harrison	6
Hays	1
Henderson	5
Hidalgo	4
Hill	5
Hopkins	5
Houston	6
Hunt	5
Jackson	2
Jasper	3
Jefferson	3
Jim Hogg	4
Jim Wells	4
Johnson	5
Karnes	2
Kaufman	5
Kendall	1
Kenedy	4
Kerr	1
Kinney	1
Kleberg	4
Lamar	5
La Salle	1
Lavaca	2
Lee	3
Leon	5
Liberty	3
Limestone	5
Live Oak	2
Llano	1
McLennan	5
McMullen	1
Madison	3
Marion	6
Mason	1
Matagorda	3
Maverick	1
Medina	1
Milam	1
Montgomery	3
Morris	6

Gulf Coast = All other Districts	
County	**TRC Distr.**
Nacogdoches	6
Navarro	5
Newton	3
Nueces	4
Orange	3
Panola	6
Polk	3
Rains	5
Real	1
Red River	6
Refugio	2
Robertson	5
Rockwall	5
Rusk	6
Sabine	6
San Augustine	6
San Jacinto	3
San Patricio	4
Shelby	6
Smith	6
Starr	4
Tarrant	5
Titus	6
Travis	1
Trinity	3
Tyler	3
Upshur	6
Uvalde	1
Val Verde	1
Van Zandt	5
Victoria	2
Walker	3
Waller	3
Washington	3
Webb	4
Wharton	3
Willacy	4
Williamson	1
Wilson	1
Wood	6
Zapata	4
Zavala	1

Appendix C. Total Drilling Depth by County by Model Rig Well Type Category

(see file “Activity_workup1.xlsx”)

Appendix D. Annual and OSD County-Level Emission Estimates

(see file “Drill_Rigs_Workup4.xlsx”)