BEFORE THE AIR QUALITY CONTROL COMMISSION
STATE OF COLORADO

IN THE MATTER OF PROPOSED REVISIONS TO REGULATIONS NUMBERS 3 & 7
DECEMBER 16-19, 2019 HEARING

**EXPERT REPORT OF MARY JANE WILSON, PRESIDENT of WZI Inc.**

# Executive Summary

I, Mary Jane Wilson, have been requested by the Environmental Defense Fund to review and submit comments on certain aspects of Prehearing Statements and related filings addressing the proposed revisions to Regulations Numbers 3 & 7. I have worked in air pollution control and participated in regulatory rule making and compliance since 1976 particularly concerning the oil and gas exploration and production industry. My resume is included as Exhibit No. 1.

My opinions and comments relate to: (1) proposed changes to reporting and permitting of vented emissions, (2) proposed changes to controls from tanks, (3) the control of emissions from water tanks greater than 2 tons per year of VOCs, (4) proposed changes to the LDAR provisions, and, (5) whether the proposed revisions would lead to the shut-in of certain wells on a large scale.

# Discussion

## 1 Removal of the Exemption for Routine and Predictable Venting from APEN and Permitting Is Reasonable.

The Division proposes to remove an exemption for routine and predictable venting of natural gas, and some Prehearing Statements object to this proposed change. This change is reasonable and will provide valuable information about emissions from oil and gas production activities. These types of emissions are knowable and can reasonably be estimated. The reporting of these emissions is currently required in California.

## 2 Amendments Proposed by the Division for Control Requirements for Storage Tanks (Sections II.C.1.e and II.C.2.b) Are Reasonable.

The Division proposes to change certain control requirements for storage tanks, such as reducing the threshold for controlling tanks to 2 tons per year of Volatile Organic Compounds (VOCs) and automatic tank gauging. Some Prehearing Statements object to certain aspects of these proposed changes.

### 2.1 Change of control threshold to tanks with emissions greater than 2 tons per year

The Division has proposed to reduce the threshold for control of tanks to 2 tons per year of VOCs, on a statewide basis. The Division evaluated the cost effectiveness of reducing emissions from tanks that emit 2 tons per year of VOCs or more by evaluating the costs and estimated emissions benefits of the controls. Some parties' Prehearing Statements object to this proposed change as not cost effective.

I have reviewed the Division's analyses of costs and emissions benefits of these controls, and conclude that they are reasonable. For example, the Division assumes a 15-year useful life for estimating the cost of flares to control tank emissions. Some industry Prehearing Statements suggest that a shorter period of amortization should be used because the flares could be installed at sites where the well(s) will be shut down in less than 15 years. In my experience, if a piece of common equipment, such as a flare, has not been utilized for its useful life for whatever reason—including when a well or number of wells are abandoned due to the economics of the situation– the equipment is not simply disposed of as salvage but rather is re-tasked for use in another installation after repairs/maintenance. Therefore, the Division properly estimated the life of the control equipment in its analysis. If a well or group of wells are predicted to have a relatively short life, rentals of control equipment may be a more cost-effective alternative. The use of a 15-year useful life assumption is appropriate in this context.

## 2.2 LDAR on tanks greater than 2 tons per year of VOCs as part of STEM

By requiring controls for tanks greater than 2 tons per year, the amendments will require LDAR to be used on tanks of that size, at the same frequency as LDAR for other components at such facilities. This will provide cost effective emissions reductions. The number of components for tanks is small compared to well installations and some process equipment, but some tank components can be a more substantial source of leaks relative to the whole tank as a source, such as a hatch being left open. Experience indicates that more frequent inspection prevents recidivism and captures new component leaks. The advent of Optical Gas Imaging (OGI) allows for the use of a combination of the flexibility of Audio, Visual, Olfactory inspection (AVO) and precision of the improved Method 21-like method using equipment-based analysis, which reflects the implementation of previous rulemakings in 2014 and 2017. The implementation of OGI, while not mandatory, presents a consistently cost-effective option to contain and capture hydrocarbons, which would otherwise be wasted, and a means to effectively conform to regulatory intent.

## 2.3 Requirement to auto gauge at tanks

The Division proposes to control emissions from tank gauging. Tank gauging without opening the hatch on the top of a tank is possible, cost effective, and simple on new and retrofitted steel tanks. The quality and quantity of the hydrocarbon liquids can be measured by a variety of techniques both old and new, which are safer than opening a tank hatch. Such techniques include automatic level measurement and control as well as sampling ports that allow samples to be collected in various levels in the tank to determine quality. The practice of degassing a tank and taking a thief sample for quality is not necessary and not as accurate as some of the other methods. In addition, the strapping of a tank, while an accurate method, is not necessary to determine the level of liquids in a properly equipped tank.

# 3 Amendments Proposed by the Division for Control Requirements for Water Tanks Are Reasonable.

The Division has proposed to delete an exemption for water tanks. While water tanks as a class may emit less than other tanks (such as tanks containing condensate or oil), control of water tanks with emissions greater than 2 tons per year of VOCs is cost effective and will achieve emissions reductions.

Relative to condensate and oil tanks, water tanks will emit a greater fraction of methane than VOCs.[1] As a result, when large volumes of produced water are produced, potential reduction in methane will be significant due to its CO2e.

The cost effectiveness of this proposal will be enhanced because the use of flares as a control device will not be on a flare-per-tank basis. Flares are typically a single unit with a header that is common to all vented systems at a tank battery. If emissions from produced water tanks are captured under the proposed regulations based on the presence of a condensate tank or oil stock tank, the same flare system would be used for all tanks as opposed to individual flares. Normally, an oil stock tank will be sited near a produced water tank, and, therefore, it is not likely that a captured produced water tank subject to flare requirements will be sited far from other tanks requiring a flare that an additional flare is required. The benefit of capturing emissions from water tanks is magnified because of the conversion of free methane to CO2, reducing the impact of the emissions by a factor of 25 times or more.

## 3.1 Control emissions from fiberglass tanks with flares

Some parties' Prehearing Statements assert that the rules should exempt fiberglass water tanks that have VOC emissions of at least 2 tons per year. This is not necessary. It is feasible to route emissions from a fiberglass produced water tank to the same control device used to control other hydrocarbon tanks. Operators may need to configure the piping to the flare from the produced water tank differently than for the other hydrocarbon tanks; however, contrary to some industry assertions, it is not necessary to install a separate flare just to control emissions from the fiberglass produced water tank.

# 4 The changes to the LDAR Program Proposed by the Division Are Cost Effective and Reasonably Estimated by the Division.

The Division has proposed to require twice-a-year LDAR inspections at all facilities that have tank batteries with uncontrolled emissions greater than 2 tons per year of VOCs. This will increase LDAR at some sites from a frequency of never, once in a lifetime, or annually. I have reviewed the methods used by the Division to estimate the cost effectiveness of LDAR. The Division, as in 2014, utilized customary and reasonable procedures to estimate the costs and the emission reductions of the revised LDAR program.

My review of the costs shows that the Division's estimate is conservative, as it does not reflect significant decreases in LDAR costs since 2014. The cost of LDAR has fallen by about 30% since it was originally required in Colorado due to lower initial costs of equipment, availability of rental equipment and training programs, and general lack of inflation in oilfield services. Increased frequency takes advantage of existing reporting tools and equipment and is not directly incremental as if it were a new program, particularly at sites already completing LDAR inspections. Thus, because the proposed rulemaking is an incremental effort stemming from prior compliance activity, the empirical reference

[1] California Air Resources Board factors (Exhibit 2) are included for reference. TCEQ study (Exhibit 3) indicates that condensate emissions factors vary considerably by location and API gravity of condensate production, from 1 to 16, this assessment conservatively uses 16.22lb VOC/bbl. EPA has developed an emissions factor for uncontrolled condensate tanks of 0.18 kg CO2e/bbl, (Exhibit 4).

economic data can be readily extrapolated to reflect future additions in the program. This is the approach taken by the Division, which is reasonable.

Determining the effectiveness of control measures using detailed estimates based on the tank/component numbers relies on a presumption of success (or some degree of success) applied to the subject population much like component-based LDAR. However, in my experience, the total number of components per well is not the major indicator of LDAR cost or emission reduction efficiency. The type and variation of components subject to any such program will vary; however, certain components, such as compressor/pump seals or open tank hatches, are the major components that require repeated attention. While the initial LDAR review of a facility will catch many leaks that are not present in later inspections, the repeated use of LDAR will identify components that are major leaking components and that are found in most oil and gas facilities due to the process requirements. This is a key reason why increasing LDAR frequency will reduce emissions.

## 4.1 Cost of LDAR

The Division employed a standard approach to estimating the cost of LDAR, including the creation of model facilities and estimating costs and benefits based on component counts.

### 4.1.1 Inflation impacts

The Division inflated the labor costs of LDAR at a rate of 5.53%.[2] Inflation, if it were the sole cost driver, would have increased all costs by approximately 6% from 2014. The Engineering News Record data below is provided for reference.

| Engineering News Record Data | | | | | |
|---|---|---|---|---|---|
| | 2009 | 2014 | 2018 | 2018-2009 | 2018-2014 |
| Building Cost Index | 5076 | 5761 | 6168 | 17.7% | 6.6% |
| Construction Cost Index | 9779 | 10740 | 11326 | 13.6% | 5.2% |
| | | | Avg. | 15.65% | 5.9% |

On this basis the cost assessment by the Division in its Final Economic Impact Analysis would have been reasonably accurate (but high for reasons outlined below).

### 4.1.2 Other cost drivers

However, several other driving factors affect the costs and incremental costs of implementation based on the economic reference date chosen for the analysis:

1. any first costs due to new equipment,
2. any new requirement at a specific location that demands added labor time, and
3. any market-based pricing on the part of third-party service providers.

[2] Economic Impact Analysis (Final) for Reg 7 at 15–16 (Nov. 5, 2019).

#### 4.1.2.1 First costs or equipment

First costs have decreased for several reasons. First, FLIR technology has continued to mature and the unit prices have decreased since 2009.[3] Additionally, many producers currently subject to LDAR requirements have already purchased equipment and trained personnel. Lastly, the Regional Air Quality Council has made rentals available to producers through their rental program for a cost of $500 per week.[4] As a result, the estimated first cost of OGI has dropped by approximately 30% since the WZI 2014 analysis.

#### 4.1.2.2 Reduced emissions from new requirements at previously excluded sites

Typically, the largest cost associated with implementing STEM and LDAR is sending additional trained personnel or third-party technicians to remote sites otherwise only subject to normal day-to-day operational visits. The new lower limit for LDAR requirements will add additional small tank batteries, but many of the sites proximate to the additional smaller tank batteries are already subject to Reg 3 and Reg 7 due to other considerations. Thus, as a practical matter, the personnel are already scheduled to be in the area and the new requirements will not necessitate an additional trip, provided the Division allows the additional tank LDAR inspections to coincide with other already-scheduled activities. Operators will schedule the tank inspections to occur at the same time as the more exhaustive facility requirements to minimize travel and additional staff-related costs. These benefits will have a greater impact in the attainment areas where the increased monitoring burden will coincide to some degree with the more remote nature of locations.

#### 4.1.2.3 Cost of contractor service technicians

In exploration and production, service costs are often related to wholesale energy prices, due largely to the changes in demand for contract services and equipment. When the price is up, additional production causes an associated demand for contractor services. An escalation of the *costs per btu produced* is a simple and efficient indication of escalating costs in production-related services. The market price impact on service prices would likely be affected by the differential relative to the current floor price and the sensitivity would be indexed relative to the change as a percentage of the current floor as opposed to the absolute change, thus imbedded in the variable costs.

Based on historic production, the Colorado market is dominated by gas as opposed to oil by several orders of magnitude, indicating that any variations in gas prices will likely translate to variations in costs of service companies. Since the gas price has been flat, the cost of service companies has also been flat to down.

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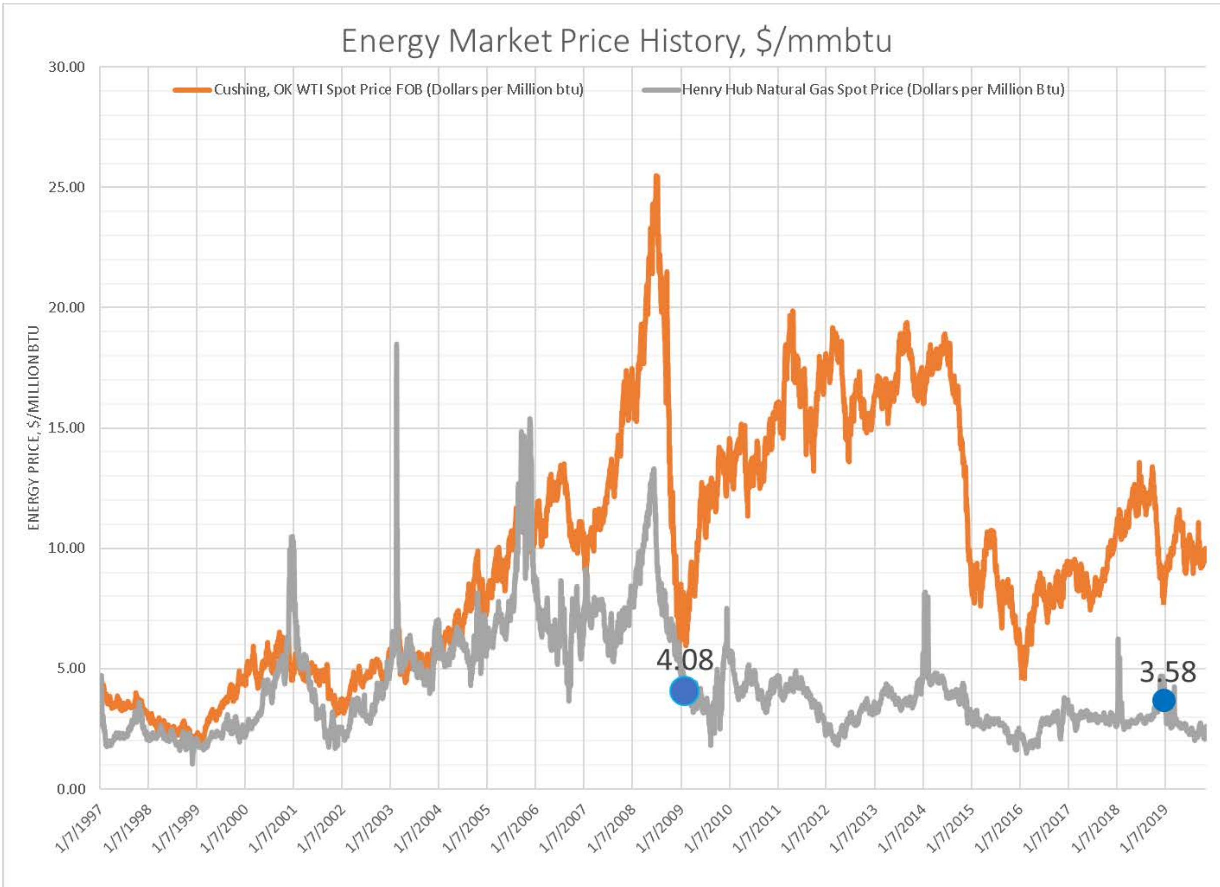
[3] WZI estimated the one-time cost of FLIR at $120,000 in our 2014 analysis. Based on updated information, current Optical Gas Imaging equipment FLIR or others has dropped to levels below $85,000. *See* Exhibit 5.

[4] *See* Exhibit 6.




From Energy Information Administration: WTI and Henry Hub Pricing

Gas pricing has been relatively stable since the 2008 period when the market relationship between oil and gas was redefined in response to the Gulf of Mexico moratorium and changes in global demands for oil as opposed to domestic gas. The price in 2009 at the start of the year was $4.08/mmbtu (average was $3.95/mmbtu). The price in 2014 at the start of the year was $4.61/mmbtu (average price was $4.31/mmbtu). The price at the beginning of 2018 was $3.58/mmbtu (average price was $2.6/mmbtu). The market price has dropped by 42% from 2014. A reasonable assumption exists that the current lowest price is the rational floor, there is a $2.02/mmbtu floor price that drives decisions to produce or not. The market price impact on service prices would likely be affected by the differential relative to the embedded costs driving the floor and the sensitivity could be lower (herein estimated to be 21%).

Therefore, the various factors indicate that the true industry costs for LDAR including repairs will be lower than 2009, not higher as would be indicated by general inflation.

# 5 The Record Does Not Support the Concept that the Rule Will Cause Substantive Adverse Economic Impacts.

I have reviewed the analysis put forth in WLG_PHS_EX-004, the Economic Risks of Proposed Revisions to AQCC Regulation No. 7 on Colorado's Rural Communities [Considine]. That report does not provide significant meaningful information about the economic impact of the proposed amendments to

Regulation 7. As set forth above, the estimated costs of the Regulation 7 amendments are in many respects overstated by the Division.

The Considine report presumes that marginal wells are singularly critical to the economic well-being of operators, but ignores the risks of underfunded operators choosing to leave marginal wells attended, unmaintained and leaking at uncontrolled rates. It presents an argument that capturing emissions from small tanks will add unreasonable costs to the operation of the marginal wells associated with the tanks. The study presents a notion that marginal operators in search of better returns are not willing participants in good maintenance practices and that any additional costs will force a shut-in due to higher variable costs on a well by well basis. Industry performance in terms of production relative to market prices is a strong indicator of resilience to various cost-related stressors such as compliance costs, increased equipment costs, etc. This indicates that oil and gas operators have capacity to absorb increases of variable costs, like those from the proposed changes to Regulation 3 and Regulation 7, through more efficient use of personnel and equipment. Regardless, the costs of the proposed regulations are not likely to have a substantive impact to production at these sites, and so the Considine analysis should not be considered relevant.

Mary Jane Wilson

**Mary Jane Wilson, WZI Inc.**

# Exhibit 1

WZI INC.

**Resume for**

# Mary Jane Wilson

**WZI Inc.**

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WZI INC

# MARY JANE WILSON, R.E.P.A.
## President

**EDUCATION/CERTIFICATION**

B.S., Petroleum Engineering, Stanford University, 1972
Registered Environmental Property Assessor, REPA 450065
State of California Accredited Lead Verifier of Greenhouse Gas Emissions Data, Executive Order H-10-173
Special Government Employee, Department of Energy Ultra-Deepwater Advisory Committee, Chair
Member, National Petroleum Council
Member, SB 83 Commission for UIC, 2018-Present
Director – Mission Bank, Audit Committee
Past Director – Greater Bakersfield Chamber of Commerce
Patent Nos. US 6,659,178 B2 Apparatus and Method For Sealing Well Bores and Bore Holes, US 6,860,997 B1 Apparatus and method for processing Organic Materials
Past Director - California Independent Petroleum Association
Past Director - Kern Economic Development Corporation and Chairman
1994 Journal of Petroleum Technology Editor, January Issue and 1994 Review Chairman
Society of Petroleum Engineers - Member since 1972, Environment Health and Safety Committee Member, 1993 Distinguished Lecturer, Co-chairman SPE/EPA Exploration & Production Environmental Conference, 1997, Chairman SPE Monograph Committee, Editor Monograph Volume 18 Henry L. Doherty Series, *Environmental Engineering for Exploration and Production Activities*
1993-94 Advisory Board - San Joaquin Valley Chapter, American Petroleum Institute
Stanford School of Earth Sciences, Stanford University - former Advisory Board and former National Fundraising Chairman
Member - Air and Waste Management Association, American Petroleum Institute, Association of Groundwater Scientists and Engineers, Central California Association of Power Producers, California Groundwater Association, California Independent Petroleum Association, California Living Museum, National Water Well Association and the Water Association of Kern County, Central California Association of Power Producers
Member at Large - Conservation Committee of California Oil and Gas Producers
Member - West Coast Advisory Group of the Petroleum Technology Transfer Council
Member - PTTC National Labs Partnership Work Group
The Council of One Hundred - California State University, Bakersfield
Future Bakersfield - Mayor's Action Team, Strategic Vision Plan
Women's Advisory Council - Girl Scouts, Joshua Tree Council
Graduate, Hill & Knowlton Media Training Seminar
Soroptimist Achievement Award, 1976 Outstanding Professional Woman, L. A. Area

## SPECIAL AREAS OF EXPERTISE:

### Regulatory Compliance:

Participates on an ongoing basis in regulatory reform programs both nationally and locally.

- Management of contracts where WZI acts as the client's representative in the coordination of business goals and permit conditions in large projects requiring interagency cooperation. This includes preparation of permit documents, technical support documents, public hearing representation and community relations.
- Provides strategic planning for compliance with regulations, the formulation of operations tracking protocols which improve agency/industry communication where permit conditions require a good understanding of a project.
- Working with regulatory agencies in the interpretation of "intent" of environmental regulations when applied to projects especially where Federal, State and local regulations are not clearly presented or have overlapping jurisdiction.
- Provides management direction on protocol design and implementation of environmental audits (site assessments, compliance audits, risk appraisals).
- Expert testimony in litigation involving groundwater contamination.
- Expert testimony and advise in litigation involving air emissions, health risk.

### Petroleum:

Serves on the National Petroleum Council. Council advises, informs and makes recommendations to the Secretary of Energy with respect to matters submitted to the Council by the Secretary of Energy representing the views of the energy industry.

- Expert Witness Moss v. Venoco, Chevron et al. for Air Emissions, Due Diligence, Standard of Care
- Appointed by Congress to advise on the operation of the Naval Petroleum Reserve No.1 (Specific Expertise in Environmental Compliance)
- Over thirty years of oil and gas operations and reservoir engineering experience.
- Prepared numerous U. S. Securities Exchange Commission Reserves Appraisals and fair market valuations on oil and gas producing properties.
- Prepared numerous enhanced oil recovery development plans.
- Economic Analysis of business alternatives in oil/gas exploration and operations both domestically and internationally.

- Negotiated settlements regarding wastewater issues of independent refineries.
- Presentation to the National Electrical Generation Association regarding California Electrical Restructuring.

**Power Generation:**

- Kern County Electrical Advisory Committee member.
- California Independent Petroleum Association Oil Producers Electrical Project member.

**PROFESSIONAL EXPERIENCE:**

1986 - Present — President, Chief Executive Officer: WZI Inc.

Defines and directs the overall management objectives of WZI Inc. Ms Wilson provides technical standards for all projects on an as-needed basis, to assure client satisfaction, monitors all projects for contract compliance and technical content.
WZI Inc. headquartered in Bakersfield, California. WZI Inc. is an environmental and consulting engineering company, which has achieved a reputation for high quality, successful project management. WZI is a State of California Verification Body for AB32 Greenhouse Gas Mandatory Reporting, Executive Order Number H-10-173. WZI offers professional and technical services in regulatory compliance (air, water, waste), geoscience, hydrology, site characterization, hazardous waste management, and environmental impact assessment. WZI offers its clients a uniquely high level of expertise, an innovative, technical approach and disciplined project management.

1982 - 1987 — Partner: Evans, Carey & Crozier

Represented numerous clients in environmental matters related to regulatory compliance and reservoir engineering. Supervised geological and groundwater studies, performed subsurface engineering and design, and made alternative recommendations, all related to hazardous and non-hazardous waste injection facilities. Expertise has been utilized in obtaining the necessary permits required by EPA, DOHS, RWQCB and various county agencies. Conducted detailed environmental assessments of hazardous waste site selections, all of which meet the demands of CEQA, and were utilized in EIR preparation.

1979 - 1982 — Consultant: Evans, Carey & Crozier

Represent Evans, Carey & Crozier with clients. Designed and implemented enhanced recovery and waste disposal programs including all permitting activities. Prepared property appraisals and evaluations.

1972 - 1979 Engineer: Texaco, Inc.

Initially, assisted in the evaluation of secondary recovery projects and pilot flood performance. Performed reservoir analysis, log interpretations and economic analyses. Based on this knowledge, was given the task of supervising all drilling and production activities for a major secondary recovery project in which she devised a new water entry survey technique. Studied the drilling potential in California, Nevada, and Alaska, and the development of several steam flood recovery projects. Asked to represent Texaco in unit negotiations, testify before government agencies and obtain all necessary permits. Also assisted in developing the Division's investment budget.

**PUBLICATIONS:**

Englehardt, John, M.J. Wilson, et al., 2001, New Abandonment Technology New Materials and Placement Techniques, S.P.E. Paper No. 66496.

Wilson, M.J. and J.D. Frederick, 1999, Editors, SPE Monograph Volume 18 Henry L. Doherty Series, Environmental Engineering for Exploration and Production Activities.

Wilson, M. J. and S. C. Kiser, 1994, Transactional Environmental Assessments: Use in the Identification of Viable Enhanced Oil Recovery Projects, S.P.E./DOE Paper No. 27782.

Wilson, M. J. and S. C. Kiser, 1993, Site Assessment Methods in Determination of Liability in Oil and Gas Property Acquisition and Divestiture, S.P.E. Paper No. 25834.

Wilson, M. J. and J. D. Frederick, 1993, Particulate Emission Testing Methodologies as Applied to Natural Gas Fired Turbines, S.P.E. Paper No. 25945.

Wilson, M. J. and S. G. Muir, 1992, A Critique of Selected Case Studies in Environmental Geophysics, S.P.E. Paper No. 23998.

Kiser, S. C., M. J. Wilson and L. M. Bazeley, 1990, Oil Field Disposal Management Practices in Western Kern County, California in proceedings from First International Symposium on Oil and Gas Exploration and Production Waste Management Practices, New Orleans, Louisiana, p.677-688.

Wilson, M. J., Kiser, S. C., E. J. Greenwood, R. N. Crozier, R. A. Crewdson, 1987, Oil Field Disposal Practices in the Hydrogeologic Setting of the Midway-Sunset and Buena Vista Oil Fields: A Review of Past Effects, Current Activities and Future Scenarios, American Association of Petroleum Geologists, Bull. V. 72, No. 3, p.394 Abs.

Wilson, M. J. and S. C. Kiser, 1987, Proceedings of Hazmacon 1986 Conference April 29 - March 1, 1986, Anaheim, California, Synergistic Approach for Siting and Design for Injection of Hazardous Liquid Wastes: Case Study in Western San Joaquin Valley, Kern County, California, S.P.E. Paper No. 16327

Wilson, M. J., 1979, The Santos: A Case History of Fractured Shale Development, S.P.E. Paper No. 7978.

Wilson, M. J., 1974, A Young Engineer's Personal Look at the "Guidelines", S.P.E. Paper No. 4913.

# Exhibit 2

# Appendix D:

# Calculation of Emission Estimates and Reductions

OVERVIEW

## A. TANK EMISSION CALCULATION

To determine the emission impact from the tank portion of the proposed regulation, staff first determined tank system count by district, using data from ARB's 2009 Oil and Gas Industry Survey (2009 Survey) to get a system count by district. For the purposes of this regulation, a tank system is considered a separator and the first crude and first water tanks tied to the separator. Staff used the separator counts in the ARB Survey as a proxy for the number of tank systems by facility per district. Staff then used Western States Petroleum Association and California Air Resources Board crude and water tank flash data to determine emission factors in metric tons per barrel of crude, water, and dry gas, produced water, for methane, volatile organic compounds (VOC), and Benzene, Toluene, Ethylbenzene, and Xylene (BTEX). The emission factors were then applied to system throughputs of crude, produced water, and dry gas, providing estimates of total methane, VOC, and BTEX emissions per system.

Staff used the estimated methane emissions by tank system to determine the number of systems that would be above the regulation's 10 metric ton per year (MT/yr) threshold for controls. Staff was then able to determine reductions assuming the 95% control efficiency in the regulation.

## B. DETAILED EXPLANATION OF THE TANK EMISSION CALCULATION

Below is a detailed explanation of how staff calculated the emission impacts on oil and gas tanks from the proposed Oil and Gas GHG Regulation.

### 1. Determining number of systems

The foundation of the tank system count analysis is the 2009 Survey. First, staff used the information in the 2009 ARB Survey to determine the number of water and crude tanks related to crude and natural gas operations. However, the 2009 ARB Survey data did not contain any information on water tanks. Since the provisions are concerned only with the separator and first crude and first water tank, staff used the counts of separators as a proxy for tank systems. Using the 2009 Survey separator data, Staff determined 14 types of separators that represented the head of a system.

Separator Names used in Tank Emission Analysis

- Condensate
- Condensate Accumulator
- Condensate Tank
- Condensate Vessel

- Free Water Knockout
- Horizontal
- Horizontal Separator
- Horizontal Separators
- Natural Gasoline Bullet
- Oil Water Separator
- Separator
- Vertical Separator
- Wash Tank
- 3-Phase

Based on this approach, staff determined that there are 2785 tank systems. They also assumed that there is at least one water tank and one crude tank attached to the separators. The 2009 Survey data contains information regarding whether or not the separators had vapor recovery systems (VRS) or were uncontrolled. Staff assumed that if the separator was equipped with a VRS, then the subsequent water and crude tanks attached to the system were also equipped with a VRS, and that if a separator was uncontrolled (not equipped with a VRS), then the subsequent water and crude tanks attached to the system also were uncontrolled. There was one exception to this assumption.

Based on discussions with the San Joaquin Valley Air Pollution Control District (SJVAPCD), staff assumed all water tanks in the SJVAPCD are uncontrolled, even if the separator is controlled. Therefore, for the systems in the SJAPCD, it was assumed that all of the water tanks were uncontrolled, even if the separator associated with the water tank was equipped with a VRS. Table D-1 shows the system counts from the 2009 Survey.

**Table D-1: System Counts**

| Category | Count | All non-VRS systems |
|---|---|---|
| Systems | 2785 | 1066 |
| Companies | 183 | 50 |
| Facilities | 731 | 523 |

## 2. Emission Factor Development

To get emission factors for methane, VOCs, and BTEX per barrel of produced crude oil and per barrel of crude oil produced water, staff used water tank flash data from Air Resources Board (ARB) testing[1] and crude and water tank flash data from Western States Petroleum Association (WSPA) tests[2]. There were 21 crude produced water tank flash tests and 17 dry gas produced water tank flash tests used from the ARB dataset. There were approximately 188 crude oil and crude produced water tank flash tests used from the WSPA dataset.

### a) Crude Oil Related Emission Factors Using WSPA Data

The WSPA crude oil flash data contained the following information:

- Crude Throughput (barrels per year (bbls/yr))
- Reid Vapor Pressure (pounds per square inch absolute (psia)) (not used in analysis)
- Crude Oil API gravity (not used in analysis)
- Flash Gas Molecular Weight (MW) (g per gram-mole (g/g-mole))
- Gas Oil Ratio (GOR) (standard cubic feet per barrel (scf/bbl))
- Methane (weight percent (wt%))
- CO2 (wt%)
- VOC  C3-C10 (wt%)
- VOC C10+ (wt%)
- BTEX (wt%)

Example Calculation using WSPA data

Example Flash Data:

| | |
|---|---|
| *Crude Throughput* | = 100,000 bbl/yr |
| *GOR* | = 1.5 scf/bbl |
| *Flash Gas MW* | = 30 g/g-mole |
| *Methane* | = 50 wt% |
| *CO2* | = 30 wt% |
| *VOC C3-C10* | = 15 wt% |
| *VOC C10+* | = 0.001 wt% |
| *BTEX (wt%)* | = 0.01 wt% |

[1] Kuo, Jeff. 2011. Methane and Carbon Dioxide Emissions from California Crude Oil and Gas Operations, California State University, Fullerton, June 30, 2011.
[2] WSPA and ARB flash test data used in this analysis is included in the back of this appendix.

To get the amount of entrained gas in the oil produced, multiply crude throughput by the GOR:

*Entrained gas* = 100,000 bbl/yr x 1.5 scf/bbl = 150,000 scf/yr

Next use the Flash Gas MW to determine the amount of emissions in metric tons:

Where:

*Base condition constant*

= 4.22119e-05 g-mole/$cm^3$ at 60 degrees F and 1 atm,

*Emissions* = Flash Gas MW x Entrained gas x base condition constant x unit conversions

= 30 g/g-mole x 150,000 scf/yr x 4.2219e-05 g-mole/$cm^3$ *28,317 $cm^3/ft^3$ x 0.002203 lb/g x 0.005 tons/lb x 0.907 MT/ton

= 8.06 MT/yr

To get the contribution of emissions by individual pollutant, multiply each pollutants weight percent as a percentage by the emissions:

*Methane emissions* = 0.5 x 8.06 MT = 4.03 MT

*BTEX emissions* = 0.0001 x 8.06 MT = 0.0008 MT

For VOC sum the weight percents of VOC C3-C10 and VOC C10+ then multiply by the emissions to get total VOC emissions:

*VOC emissions* = (0.15 + 0.00001) x 8.06 MT = 1.21 MT

To convert the emissions to an emission factor, divide each pollutant's emissions by the total crude throughput of the tank.

*Methane Emission Factor* = 4.03MT/ 100,000 bbl = 4.03e-5 MT/bbl

*BTEX Emission Factor* = 0.0008 MT / 100,000 bbl = 8e-9 MT/bbl

*VOC Emission Factor* = 1.21 MT / 100,000bbl = 1.21e-5 MT/bbl

The WSPA water flash data contained the following information:

- Water Throughput (bbls/yr)
- Flash Gas MW (g/g-mole)

- Gas Water Ratio (GWR) (scf/bbl)
- Methane (wt%)
- $CO_2$ (wt%)
- VOC  C3-C10 (wt%)
- VOC C10+ (wt%)
- BTEX (wt%)

The calculation for the water tank emission factors is the same as the crude emission factor calculations above, except the water tank emission factors uses GWR instead of GOR and water throughput instead of crude throughput.

**b) Crude Oil Related Emission Factors Using ARB Data**

The calculation for developing the crude oil related emission factors using ARB data is nearly identical to the calculation using WSPA data. The only exception is that the ARB data was speciated by individual compound.  So the individual VOCs and BTEX compounds had to be manually added together to create similar pollutant categories as the WSPA data.

**c) Combined Crude Oil Related Emission Factors**

The throughputs and the individual pollutant emissions were summed from the ARB and WSPA datasets and an overall emission factor was determined from the total of the summed datasets, as shown in Tables D-2 through D-7.

**Table D-2: Crude Methane Emission Factor**

| Dataset | Crude Throughput (bbl/yr) | Methane (MT/yr) | Methane Emission Factor (MT/bbl) |
|---|---|---|---|
| ARB | N/A | N/A | |
| WSPA | 96,376,935 | 5,910 | |
| **Total** | **96,376,935** | **5,910** | **6.13E-05** |

**Table D-3: Crude VOC Emission Factor**

| Dataset | Crude Throughput (bbl/yr) | VOC (MT/yr) | VOC Emission Factor (MT/bbl) |
|---|---|---|---|
| ARB | N/A | N/A | |
| WSPA | 96,376,935 | 5,097 | |
| **Total** | 96,376,935 | 5,097 | **5.29E-05** |

**Table D-4: Crude BTEX Emission Factor**

| Dataset | Crude Throughput (bbl/yr) | BTEX (MT/yr) | BTEX Emission Factor (MT/bbl) |
|---|---|---|---|
| ARB | N/A | N/A | |
| WSPA | 11,976,536 | 0.50 | |
| **Total** | **11,976,536** | **0.50** | **4.21E-08** |

**Table D-5: Crude Produced Water Methane Emission Factor**

| Dataset | Water Throughput (bbl/yr) | Methane (MT/yr) | Methane Emission Factor (MT/bbl) |
|---|---|---|---|
| ARB | 28,506,500 | 116 | |
| WSPA | 1,361,401,787 | 8,145 | |
| **Total** | **1,389,908,288** | **8,261** | **5.94E-06** |

**Table D-6: Crude Produced Water VOC Emission Factor**

| Dataset | Water Throughput (bbl/yr) | VOC (MT/yr) | VOC Emission Factor (MT/bbl) |
|---|---|---|---|
| ARB | 28,506,500 | 41 | |
| WSPA | 1,321,470,497 | 805 | |
| **Total** | **1,349,976,997** | **846** | **6.26E-07** |

**Table D-7: Crude Produced Water BTEX Emission Factor**

| Dataset | Water Throughput (bbl/yr) | BTEX (MT/yr) | BTEX Emission Factor (MT/bbl) |
|---|---|---|---|
| ARB | 23,031,500 | 2.68 | |
| WSPA | 10,047 | 0.0017 | |
| **Total** | **23,041,547** | **2.68** | **1.17E-07** |

### d) Natural Gas Emission Factors

The ARB data also contained 19 flash tests on dry gas produced water. The dry gas produced water emission factors came from these 19 flash tests.

*Dry Gas Produced Water Methane Emission Factor*

= 4.73e-05 MT/bbl

*Dry Gas Produced Water VOC Emission Factor*

= 6.59e-06 MT/bbl

*Dry Gas Produced Water BTEX Emission Factor*

= 6.51e-07 MT/bbl

**3. Emission Estimates by System for All Systems**

Staff used the emission factors above to estimate emissions from each tank system identified in the 2009 ARB Survey. In order to do so, throughput of crude, dry gas, crude oil produced water, and dry gas produced water is necessary.

The 2009 Survey contained throughput data for each separator. However, when staff compared the separator throughput with overall facility throughput, many survey respondents used their facility throughput as their separator throughput. In instances where a facility had multiple separators that represented system heads, this led to an overestimate of the system throughputs. This overestimate of the system throughputs led to an overestimate of the calculated emissions. In order to combat the prevalent issue of survey respondents using their facility throughput as their separator throughput, staff decided to divide the facility throughput by the number of separators that represented system heads at each facility. This gave each separator a proportion of the totally facility throughput. Staff used this method for every facility, even if the facility appeared to report its separator throughput correctly.

**a) Crude Oil Produced Water**

The 2009 Survey did not contain crude produced water data, but did contain crude throughput data. Staff used 2007 Division of Oil, Gas, and Geothermal Resources (DOGGR) statewide data on crude and produced water throughput to develop a ratio of water to crude[3]. The 2007 DOGGR statewide data showed that oil and condensate totals were approximately 243,000,000 barrels (bbls) and water totals were approximately 2,550,000 bbls. These totals show that the oil and condensate represent about 10 percent of the total water throughput, verifying staff's proposed ratio. As a result, staff used the following formula to determine crude oil produced water:

$$Facility\ Crude\ Oil\ Produced\ Water\ (bbls) = \frac{Factilty\ Crude\ Throughput\ (bbls\ )}{0.10}$$

**b) Dry Gas Produced Water**

The 2009 Survey did not contain dry gas produced water data, but did contain dry gas throughput data. Staff used the 2007 DOGGR statewide data from dry gas counties (Butte, Colusa, Glenn, Humboldt, Madera, San Joaquin, Sutter, Tehama, and Yolo) to calculate a ratio of dry gas to dry gas produced water[1]. The amount of dry gas for those counties was 22,048,095 thousand cubic feet (MCF) and the amount of dry gas produced water was 446,950 bbls. This leads to a ratio of 49,330 SCF of dry gas per barrel of produced water. As a result, staff used the following formula to determine dry gas oil produced water:

$$Factily\ Dry\ Gas\ Produced\ Water\ (bbls) = \frac{Factility\ Dry\ Gas\ Throughput\ (SCF)}{49{,}330\ (\frac{SCF}{bbl})}$$

**c) Methane, VOC and BTEX Emission Calculations**

To calculate emissions from the tanks systems, Staff multiplied the system throughput by the emission factor

For example,

Crude throughput for System X

= 100,000 bbls

Water throughput for System X

[3] DOGGR. 2008. 2007 Annual Report of the State Oil & Gas Supervisor, Publication no. PR06.

= 1,000,000 bbls

Crude Methane Emissions

= 100,000 bbls * 6.13E-5 MT/bbl = 6.13 MT

Crude VOC Emissions

= 100,000 bbls * 5.29E-05 MT/bbl = 5.29 MT

Crude BTEX Emissions

= 100,000 bbls * 4.21E-08 MT/bbl = 0.00421 MT

Crude Water Methane Emissions

= 1,000,000 bbls * 5.94E-6 MT/bbl = 5.94 MT

Crude Water VOC Emissions

= 1,000,000 bbls * 6.26E-07 MT/bbl = 0.626 MT

Crude Water BTEX Emissions

= 1,000,000 bbls * 1.17E-07 MT/bbl = 0.117 MT

If this system were uncontrolled, it would be considered subject to the regulation because the total methane emissions are above 10 MT (6.13 MT + 5.94 MT = 12.07 MT). This calculation is performed on every system at each facility to determine the number of systems that would be subject to the storage tank regulation. For dry gas systems, dry gas throughput was used instead of crude throughput to determine the methane emissions from the system.

### d) Oxides of Nitrogen (NOx), Carbon Monoxide (CO), HYDROCARBON (HC), PARTICULATE MATTER (PM), and OXIDES OF SULFUR (SOx) EMISSION CALCULATIONS

In order to estimate emissions related to combustion from vapor recovery, Staff needed appropriate emission factors. Staff used emission factors from the United States Environmental Protection Agency (U.S. EPA) entitled, Emissions Factors & AP 42, Compilation of Air Pollutant Emission Factors for flares[45]. Table D-8 shows the existing flare emissions factors.

[4] U.S. EPA. 2016. Natural Gas Combustion. AP 42, Fifth Edition, Volume I.Chapter 1: External Combustion Sources**.**

[5] U.S. EPA. 2016. Industrial Flares. AP 42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources.

**Table D-8: Flare Emission Factors**

| Pollutant | Emission Factor (lb/10^6 scf) |
|---|---|
| NOx | 68 |
| CO | 370 |
| Hydrocarbons | 140 |
| CO2 | 120000 |
| Lead | 0.0005 |
| N2O (Uncontrolled | 2.2 |
| N2O (low nox burner) | 0.64 |
| PM (Total) | 7.6 |
| PM10 (condensable) | 5.7 |
| PM2.5 (filterable) | 1.9 |
| SO2 | 0.6 |
| TOC | 11 |
| Methane | 2.3 |
| VOC | 5.5 |
| Benzene | 2.10E-03 |
| Toluene | 3.40E-03 |

For the low-NOx incinerator emission factors, staff used a combination of test data and manufacturer reported emission factors. For NOx, CO, and hydrocarbons, Staff used manufacturer reported emission factors[6]. For PM and SOx, manufacturer test data was used to determine emission factors for those pollutants[7]. For PM, the PM emissions were measured as PM10 in the actual test data. However, the manufacturer indicated that the PM10 test data included PM2.5 in the result. In order to get a PM2.5 and a PM10 emission factor, staff used the ratio of PM10 to PM2.5 from the flare emission factors and applied it to the low-NOx incinerator PM10 emission result. This gave a PM2.5 and a PM10 emission factor proportional to the flare emission factors for the same pollutants. Table D-9 shows the low-NOx incinerator emission factors.

[6] Aeron. 2015. Certified Ultra Low Emissions Burner, Sheets CEB 50 through CEB 1200:
[7] Aeron 2011 – 2013. Summary of Test Results, low-NOx incinerator test data submitted to ARB.

**Table D-9: Low-NOx Incinerator Emission Factors**

| Pollutant | Emission Factor (lb/10^6 scf) |
|---|---|
| NOx | 18.00 |
| CO | 10.00 |
| Hydrocarbons | 5.00 |
| PM Total | 7.23 |
| PM10 | 5.42 |
| PM2.5 | 1.81 |
| SOx | 0.04 |

Once staff had the emission factors for both flares and low-NOx incinerators, the next step was to determine the amount of gas that was going to be flared/incinerated. From the 2009 Survey staff could determine what kind of VRS was on each system. For systems that had no VRS, it was assumed that a low-NOx incinerator would have to be installed to deal with the captured gas. For facilities that had existing flares for VRS, it was assumed that they would replace their smallest flare with a low-NOx incinerator and any gas that going to the replaced smallest flare plus the additional captured gas would now go to the low-NOx incinerator. For facilities that had other VRS disposal methods such as disposal wells, collection systems, or steam turbines, it was assumed that the additional gas that would be captured would be routed to those same disposal methods. From the 2009 Survey, staff determined that there were 26 systems that were uncontrolled. These 26 systems spanned 5 facilities. However, one of the facilities had systems that were spread miles apart. Therefore, it was determined for that one facility three flare replacements would need to occur to capture the non-VRS systems that were spread apart.

In addition to the non-VRS systems, staff had discussions with the SJVAPCD and discovered that almost all of the water tanks in the San Joaquin Valley were uncontrolled. Therefore, for this analysis, staff assumed all water tanks were uncontrolled in the SJVAPCD. From the 2009 Survey, staff determined that there were 291 systems spanning 17 facilities that needed VRS controls on their water tanks because their systems were above 10 MT of methane emissions. Of the 17 facilities, 7 facilities were using flares as VRS for their controlled systems. The other 10 facilities were assumed to route their additional captured water tank to their other methods of disposal.

The next step was to determine the emissions from the existing flares. The 2009 Survey contained the throughput of each flare. Therefore, staff just multiplied the emission factors in Table D-6 by the throughput of the smallest flare on each facility. For the non-VRS systems, the total throughput of the smallest flare on each facility was 33,508,028 standard cubic feet (SCF) of gas. For the non-VRS water tank systems the total throughput of the smallest flare on each facility was 147,601,681 SCF.

Now that a baseline of emissions had been established, the next step was to determine the amount of emission if the smallest flares were replaced with low-NOx incinerators. To do this, staff multiplied the existing smallest flare throughput with the low-NOx incinerator emission factors in Table D-9.

The next step was to determine the amount of additional gas that would be captured and sent to the low-NOx incinerator. Staff converted the amount of methane emissions estimated to be vented from the uncontrolled systems to gas. Staff assumed a methane composition of 78.8 percent.

Example of converting methane emissions to gas

Assumptions:

Methane Density = 0.0419 lb/ft$^3$

1 ton = 2000 lbs

1 Metric ton = 0.907 tons

Methane Mole Fraction 0.788

Convert 10 MT methane to gas:

$$\frac{10\ MT\ CH4}{0.907\,\frac{MT}{ton}} \times 2000\,\frac{lbs}{ton} \times \frac{1}{0.0419\frac{lb}{ft3}} \times \frac{1}{0.788} = 667{,}855\ ft3$$

The total amount of additional gas captured from the non-VRS systems was calculated to be 31,074,810 SCF. The total amount of additional captured from the the non-VRS water tanks was calculated to be 292,184,404. The total additional gas captured was calculated to be 323,259,214 SCF. Multiply the total additional gas captured by the emission factors in Table D-9.

To determine the emission impacts of NOx, CO, HC, PM, and SOx from the combustion of the captured gas, staff added the emissions from the existing gas using the low-NOx incinerator and the emissions from the additional gas sent to the low-NOx incinerator and subtract the emissions from the existing flare. Table D-10 shows the total emissions impact from non-methane pollutants.

**Table D-10: Total Emission Impact From Non-Methane Pollutants**

| Pollutant | Non- VRS Systems Emissions (tons) | Non-VRS Water Tank Emissions (tons) | Total Emissions (tons) |
|---|---|---|---|
| NOx | -0.56 | -1.06 | -1.62 |
| CO | -5.88 | -25.11 | -30.98 |
| Hydrocarbons | -2.18 | -9.23 | -11.42 |
| PM Total | 0.11 | 1.03 | 1.13 |
| PM10 | 0.08 | 0.77 | 0.85 |
| PM2.5 | 0.03 | 0.26 | 0.28 |
| SOx | -0.0088 | -0.0355 | -0.0442 |

### e) Natural Gas Speciation

Throughout the emissions analysis staff assumed that all gas was 78.8 percent methane. Staff used a speciation for gas found in a August 2009 API Compendium of Greenhouse Gas Methodologies[8] and ratioed up the species to reflect a 78.8 percent composition. This ratioed up speciation was applied to the methane emission reductions from each major component of the regulation to determine the reductions from VOCs, HCs, Benzene, Toluene, Ethyl-Benzene and Xylenes. Table D-11 shows the speciation fraction used in the July 1996 API study and the adjusted speciation fraction ratioed up to 78.8 percent that was used in this analysis.

[8] API. 2009. Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009.

**Table D-11: Gas Speciation**

| Pollutant | API 2009 Average Speciation Fraction | Average Speciation Ratioed to 78.8 |
|---|---|---|
| Methane | 0.766 | 0.788 |
| Non-Methane | 0.2342 | 0.212 |
| VOC | 0.144 | 0.130350128 |
| C6+ | 0.010232 | 0.009262101 |
| Benzene | 0.002482 | 0.002246729 |
| Toluene | 0.001158 | 0.001048232 |
| Ethyl-Benzene | 0.000174 | 0.000157506 |
| Xylenes | 0.000898 | 0.000812878 |

### f) NOx Emissions from Well stimulation Circulation Tanks

Staff calculated NOx emissions based on the amount of methane being captured from requiring vapor controls on well stimulation circulation tanks. In Appendix B, it is estimated that the vapor controls on well stimulation circulation tanks will result in 68 tons of methane reduction a year. This is equivalent to approximately 4,525,000 SCF of gas. Multiply this volume of gas by the NOx emission factor in Table D-9 and you get 81.45 pounds of NOx or 0.041 tons of NOx per year.

## 4. VOC to Methane Equivalency Analysis

The average VOC speciation fraction of natural gas from API 2009 is 0.13 (See Table D-11). Six tons of VOC is equivalent to approximately 46 tons of total emissions. The assumed speciation of methane in natural gas is 0.788 throughout this document. Therefore, 6 tons of VOC is equivalent to 36 tons of methane.

$$\frac{VOC\ tons}{VOC\ spectiaon} = \frac{6\ tons}{0.13} = 46\ tons\ of\ total\ emissions$$

$$total\ emissions\ tons * methane\ speciation = \ 46\ tons\ * 0.788$$
$$= 36\ tons\ of\ methane$$

## 5. Throughput Threshold Analysis

In order to reduce the amount of unnecessary flash testing for small oil and gas operators, staff analyzed flash testing data and system throughput data to determine throughput threshold that would exempt facilities below the threshold from having to do flash test on their systems. In order to bracket the problem staff looked at the highest GOR and the highest GWR from the ARB and WSPA flash test data and applied them to the system throughputs at each facility. Staff then looked at which throughput levels equaled 10 MT of methane. The throughput levels for systems at 10 MT of methane were 5.5 barrels of oil per day (BOPD) and 367 barrels of water per day (BWPD) for crude systems and 208 BWPD for dry gas systems. This established an upper end bracket for a crude throughput and a water throughput that would virtually ensure that no system that would be exempted from flash testing would exceed 10 MT of methane. Once the upper end bracket was established, staff started easing the thresholds upwards to see how high the thresholds could go while still be effective at preventing excess emissions. Staff eventually pushed the crude threshold up to 50 BOPD and were considering a crude only threshold limit for crude systems. So staff decided to test the 50 BOPD threshold on the WSPA flash data. At 50 BOPD there were 4 WSPA tanks systems that would exceed 10 MT of methane and not be required to flash test. So staff decided to reinstitute the water throughput threshold. However, staff wanted to make the regulation simpler by having one set of threshold limits that applied to both crude and dry gas systems, instead of separate threshold limits for each. Since staff pushed the crude throughput threshold limit up to 50 BOPD, it was decided that the rounded dry gas water threshold upper limit should be used for the water threshold. So the crude throughput threshold limit of 50 BOPD and the water throughput threshold limit of 200 BWPD were settled upon. Staff ran some analysis to see the effects of these new threshold limits. The 50 BOPD and the 200 BWPD threshold limits captured every system in the 2009 Survey and the WSPA flash data that would exceed 10 MT of methane with a compliance margin in case of high flash test data. The 50 BOPD and the 200 BWPD limits would exempt about 1500 out of approximately 2600 systems from flash testing. Whereas the 50 BOPD only limit would exempt 1700 out of 2600 systems.

.

## Table D-12: ARB Fullerton Crude Water Data

| Crude Oil Produced Water | Crude Water Tanks System 1 | Crude Water Tanks System 2 | Crude Water Tanks System 3 | Crude Water Tanks System 4 | Crude Water Tanks System 5 | Crude Water Tanks System 6 | Crude Water Tanks System 7 | Crude Water Tanks System 8 | Crude Water Tanks System 9 | Crude Water Tanks System 10 | Crude Water Tanks System 11 | Crude Water Tanks System 12 | Crude Water Tanks System 13 | Crude Water Tanks System 14 | Crude Water Tanks System 15 | Crude Water Tanks System 16 | Crude Water Tanks System 17 | Crude Water Tanks System 18 | Crude Water Tanks System 19 | Crude Water Tanks System 20 | Crude Water Tanks System 21 | Crude Water Tanks System 22 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Water Sample Association | Crude | Crude | Crude | Crude | Crude | Crude | Crude | Crude | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil | Crude Oil |
| Date Sampled | 2/1/2011 | 3/30/2011 | 3/30/2011 | 3/30/2011 | 2/10/2011 | 2/1/2011 | 2/1/2011 | 2/1/2011 | 7/19/2010 | 7/19/2010 | 6/13/2011 | 6/13/2011 | 6/14/2011 | 8/3/2011 | 8/3/2011 | 7/29/2011 | 7/29/2011 | 8/1/2011 | 8/1/2011 | 8/2/2011 | 8/2/2011 | 8/2/2011 |
| Date Analyzed | 3/3/2011 | 4/7/2011 | 4/7/2011 | 4/6/2011 | 3/7/2011 | 3/3/2011 | 3/3/2011 | 3/3/2011 | 7/29/2010 | 7/29/2010 | 9/14/2011 | 9/13/2011 | 9/14/2011 | 9/13/2011 | 9/13/2011 | 9/14/2011 | 9/14/2011 | 9/14/2011 | 9/13/2011 | 9/13/2011 | 9/13/2011 | 9/14/2011 |
| Job Number | J11220 | J11870 | J11870 | J11869 | J11218 | J11217 | J11221 | J11221 | J04256 | J04255 | J14913 | J14910 | | | J14905 | J14903 | J14902 | J14909 | J14911 | J14908 | J14912 | J14900 |
| **API Gravity of Associated Crude** | **26.46** | **16.5** | **13** | **15** | **32** | **32** | **19.11** | **19.11** | **24.22** | **36.57** | **15** | **15.9** | **19.8** | **15.5** | **12.91** | **17.47** | **17.13** | **11** | **11** | **12** | **14.08** | **12** |
| | | | | | | | | | | | | | | | | | | | | | | |
| Air District | SBAPCD | SJV | SJV | SJV | SCAQMD | SCAQMD | SCAQMD | SCAQMD | SJV | SJV | SJV | SJV | SJV | SJV | SJV | SCAQMD | SCAQMD | SJV | SJV | SJV | SCAQMD | SJV |
| | | | | | | | | | | | | | | | | | | | | | | |
| Sample Pressure (psig) | | 22 | 30 | 34 | 100 | 17 | 142 | 140 | 60 | 48 | 40 | 40 | 27 | 49 | 45 | 80 | 90 | 40 | 50 | 30 | 8 | 60 |
| Sample Temperature (deg F) | 70 | 78 | 68 | 180 | 102 | 100 | 137 | 131 | 110 | N/A | 152 | 70 | 70 | 110 | 180 | 69 | 69 | 220 | 160 | 240 | 218 | 215 |
| Gas-Water-Ratio (ft^3/bbl) | 0.39 | 0.94 | 1.29 | 0.49 | 1.18 | 0.44 | 1.32 | 1.20 | 0.54 | 0.59 | 1.84 | 1.00 | 0.34 | 0.17 | 0.66 | 1.55 | 1.21 | 0.48 | 0.81 | 0.23 | 0.03 | 0.30 |
| Base Conditions (Flashed to) | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F |
| Throughput (bbl/day) | 7 | 1,000 | 75 | 1,000 | 18 | 800 | 1,200 | 6,500 | 6,000 | 4,500 | 207 | 924 | 1,298 | 2 | 3,663 | 1,204 | 1,742 | 3,680 | 1,380 | 17,000 | 10,900 | 15,000 |
| **Chromatograph Compounds** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** |
| Nitrogen | 8.46 | 0 | 0 | 0 | 0.269 | 2.34 | 0 | 0.199 | 7.326 | 6.818 | 0 | 0 | 0.121 | 0 | 0 | 0 | 0 | 0 | 1.029 | 0 | 0 | 0.542 |
| Carbon Dioxide | 46.997 | 88.82 | 91.394 | 84.152 | 24.621 | 15.009 | 47.363 | 42.839 | 44.874 | 23.601 | 92.325 | 88.757 | 54.987 | 31.613 | 86.705 | 63.266 | 65.578 | 81.421 | 84.869 | 80.073 | 77.52 | 78.122 |
| Methane | 16.237 | 8.887 | 6.231 | 6.725 | 45.384 | 26.843 | 41.456 | 50.069 | 31.522 | 11.236 | 5.943 | 7.422 | 28.501 | 62.803 | 10.539 | 27.37 | 29.774 | 12.875 | 5.829 | 12.616 | 8.972 | 20.053 |
| Ethane | 2.883 | 0.063 | 0.764 | 0.353 | 11.033 | 11.871 | 2.246 | 2.803 | 5.121 | 16.656 | 0.885 | 0.723 | 2.288 | 0.374 | 0.461 | 1.779 | 1.244 | 0.0823 | 0.313 | 0.348 | 0.437 | 0.576 |
| Propane | 2.809 | 0.032 | 0.025 | 0.142 | 10.434 | 18.557 | 1.713 | 0.997 | 3.003 | 20.854 | 0.396 | 0.105 | 4.92 | 0.079 | 0.079 | 0.916 | 0.727 | 0.983 | 5.057 | 1.203 | 0.253 | 0.295 |

| Crude Oil Produced Water | Crude Water Tanks System 1 | Crude Water Tanks System 2 | Crude Water Tanks System 3 | Crude Water Tanks System 4 | Crude Water Tanks System 5 | Crude Water Tanks System 6 | Crude Water Tanks System 7 | Crude Water Tanks System 8 | Crude Water Tanks System 9 | Crude Water Tanks System 10 | Crude Water Tanks System 11 | Crude Water Tanks System 12 | Crude Water Tanks System 13 | Crude Water Tanks System 14 | Crude Water Tanks System 15 | Crude Water Tanks System 16 | Crude Water Tanks System 17 | Crude Water Tanks System 18 | Crude Water Tanks System 19 | Crude Water Tanks System 20 | Crude Water Tanks System 21 | Crude Water Tanks System 22 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Isobutane | 0.591 | 0.008 | 0.012 | 0.055 | 0.946 | 4.345 | 0.964 | 0.396 | 0.509 | 2.763 | 0.086 | 0.027 | 1.526 | 0.052 | 0.009 | 0.299 | 0.178 | 0.008 | 0.01 | 0.035 | 0.045 | 0 |
| n-Butane | 2.249 | 0.023 | 0.039 | 0.19 | 2.952 | 8.565 | 1.683 | 0.547 | 1.407 | 8.227 | 0.134 | 0.062 | 2.286 | 0.087 | 0.005 | 0.684 | 0.367 | 0.263 | 0.056 | 0.156 | 0.089 | 0.286 |
| 2,2 Dimethyl propane | 0.741 | 0.009 | 0.022 | 0.048 | 0.098 | 0 | 0.126 | 0.068 | 0 | 0.083 | 0 | 0.009 | 0.056 | 0.02 | 0.006 | 0.031 | 0.04 | 0.062 | 0.013 | 0.021 | 0.055 | 0 |
| Isopentane | 0.907 | 0.049 | 0.042 | 0.141 | 0.485 | 3.105 | 1.113 | 0.203 | 0.676 | 2.012 | 0 | 0.02 | 0.869 | 0.02 | 0.006 | 0.297 | 0.114 | 0.05 | 0.005 | 0.021 | 0.055 | 0 |
| n-Pentane | 1.042 | 0.019 | 0.045 | 0.229 | 0.431 | 2.516 | 0.898 | 0.135 | 0.627 | 1.78 | 0 | 0.006 | 0.666 | 0.02 | 0.006 | 0.193 | 0.032 | 0.05 | 0.013 | 0.086 | 0.027 | 0 |
| 2,2 Dimethyl butane | 0.297 | 0.002 | 0.002 | 0.008 | 0.007 | 0.071 | 0.06 | 0.011 | 0.037 | 0.039 | 0.002 | 0.002 | 0.029 | 0.045 | 0.023 | 0.026 | 0.015 | 0.014 | 0.002 | 0.021 | 0.119 | 0 |
| Cyclopentane | 0.108 | 0.009 | 0.005 | 0.026 | 0.344 | 0.37 | 0.06 | 0.057 | 0.146 | 0.083 | 0.014 | 0.03 | 0.049 | 0.119 | 0.058 | 0.042 | 0.039 | 0.047 | 0.004 | 0.03 | 0.407 | 0 |
| 2,3 Dimethyl butane | 0.454 | 0.007 | 0.013 | 0.074 | 0.014 | 0.079 | 0.063 | 0.026 | 0.05 | 0.374 | 0.004 | 0.02 | 0.052 | 0.04 | 0.041 | 0.088 | 0.036 | 0.019 | 0.004 | 0.016 | 0.066 | 0 |
| 2 Methylpentane | 1.568 | 0.121 | 0.115 | 0.594 | 0.131 | 0.59 | 0.331 | 0.059 | 0.387 | 0.428 | 0.015 | 0.197 | 0.32 | 0.174 | 0 | 0.128 | 0.038 | 0.084 | 0.03 | 0.089 | 0.213 | 0 |
| 3 Methylpentane | 1.293 | 0.182 | 0.171 | 0.832 | 0.124 | 0.375 | 0.204 | 0.059 | 0.365 | 0.328 | 0.011 | 0.309 | 0.259 | 0.15 | 0 | 0.151 | 0.062 | 0.11 | 0.046 | 0.098 | 0.166 | 0 |
| n-Hexane | 1.602 | 0.713 | 0.569 | 2.775 | 0.227 | 0.675 | 0.394 | 0.066 | 1.269 | 0.865 | 0.022 | 1.172 | 0.729 | 0.344 | 0.09 | 0.233 | 0.071 | 0.296 | 0.176 | 0.226 | 0.517 | 0 |
| Methylcyclopentane | 0.665 | 0.136 | 0.125 | 0.661 | 0.437 | 0.696 | 0.176 | 0.136 | 0.459 | 0.394 | 0.019 | 0.285 | 0.225 | 0.051 | 0 | 0.28 | 0.121 | 0.152 | 0.055 | 0.114 | 0 | 0 |
| Benzene | 0.052 | 0.018 | 0.006 | 0.042 | 0.535 | 0.532 | 0.051 | 0.05 | 0.398 | 1.685 | 0.008 | 0.004 | 0.029 | 0.158 | 0.056 | 0.023 | 0.038 | 0.056 | 0.012 | 0.199 | 0.386 | 0 |
| Cyclohexane | 0.44 | 0.145 | 0.139 | 0.821 | 0.208 | 0.476 | 0.241 | 0.093 | 0.544 | 0.258 | 0.019 | 0.391 | 0.264 | 0.04 | 0 | 0.283 | 0.15 | 0.019 | 0.011 | 0.066 | 1.033 | 0 |
| 2-Methylhexane | 0.575 | 0.008 | 0.005 | 0.066 | 0.025 | 0.119 | 0.066 | 0.021 | 0.133 | 0.133 | 0.003 | 0.02 | 0.08 | 0.033 | 0 | 0.033 | 0.007 | 0.017 | 0.003 | 0.024 | 0.191 | 0 |
| 3-Methylhexane | 0.64 | 0.008 | 0.008 | 0.064 | 0.029 | 0.129 | 0.058 | 0.021 | 0.133 | 0.133 | 0.005 | 0.01 | 0.09 | 0.104 | 0 | 0.063 | 0.014 | 0.031 | 0.005 | 0.03 | 0.2 | 0 |
| 2,2,4 Trimethyl pentane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other C7's | 1.8 | 0.289 | 0.095 | 0.437 | 0.196 | 0.51 | 0.158 | 0.38 | 0.281 | 0.254 | 0.015 | 0.207 | 0.239 | 1.049 | 0.09 | 0.746 | 0.211 | 0.366 | 0.15 | 0.43 | 1.546 | 0 |
| n-Heptane | 1.105 | 0.01 | 0.01 | 0.14 | 0.041 | 0.228 | 0.085 | 0.03 | 0.18 | 0.215 | 0.005 | 0.008 | 0.141 | 0.071 | 0.038 | 0.023 | 0.003 | 0.019 | 0.02 | 0.214 | 0.144 | 0 |
| Methylcyclohexane | 1.072 | 0.023 | 0.015 | 0.326 | 0.134 | 0.44 | 0.194 | 0.075 | 0.127 | 0.149 | 0.012 | 0.025 | 0.197 | 0.203 | 0.071 | 0.321 | 0.084 | 0.079 | 0.067 | 0.428 | 0.842 | 0 |
| Toluene | 0.098 | 0.012 | 0.007 | 0.097 | 0.368 | 0.425 | 0.082 | 0.059 | 0.096 | 0.307 | 0.005 | 0.012 | 0.052 | 0.208 | 0.138 | 0.012 | 0.032 | 0.066 | 0.077 | 0.579 | 1.117 | 0 |
| Other C8's | 2.345 | 0.075 | 0.069 | 0.434 | 0.123 | 0.454 | 0.09 | 0.221 | 0.194 | 0.202 | 0.017 | 0.031 | 0.299 | 0.409 | 0.1 | 1.294 | 0.363 | 0.192 | 0.072 | 0.681 | 1.285 | 0 |
| n-Octane | 0.509 | 0.012 | 0.006 | 0.084 | 0.014 | 0.06 | 0.013 | 0.019 | 0.049 | 0.042 | 0.003 | 0.006 | 0.065 | 0.107 | 0.061 | 0.008 | 0.031 | 0.022 | 0.02 | 0.22 | 0.158 | 0 |
| Ethylbenzene | 0.051 | 0.008 | 0.005 | 0.026 | 0.031 | 0.028 | 0.016 | 0.027 | 0.019 | 0.003 | 0.003 | 0.005 | 0.021 | 0.125 | 0.028 | 0.077 | 0.069 | 0.035 | 0.016 | 0.055 | 0.291 | 0 |

| **Crude Oil Produced Water** | **Crude Water Tanks System 1** | **Crude Water Tanks System 2** | **Crude Water Tanks System 3** | **Crude Water Tanks System 4** | **Crude Water Tanks System 5** | **Crude Water Tanks System 6** | **Crude Water Tanks System 7** | **Crude Water Tanks System 8** | **Crude Water Tanks System 9** | **Crude Water Tanks System 10** | **Crude Water Tanks System 11** | **Crude Water Tanks System 12** | **Crude Water Tanks System 13** | **Crude Water Tanks System 14** | **Crude Water Tanks System 15** | **Crude Water Tanks System 16** | **Crude Water Tanks System 17** | **Crude Water Tanks System 18** | **Crude Water Tanks System 19** | **Crude Water Tanks System 20** | **Crude Water Tanks System 21** | **Crude Water Tanks System 22** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| M & P Xylenes | 0.101 | 0.017 | 0.003 | 0.044 | 0.083 | 0.087 | 0.033 | 0.036 | 0.015 | 0.018 | 0.003 | 0.011 | 0.082 | 0.264 | 0.182 | 0.042 | 0.029 | 0.05 | 0.099 | 0.377 | 0.724 | 0 |
| O-Xylene | 0.027 | 0.006 | 0 | 0.016 | 0.031 | 0.024 | 0.008 | 0.009 | 0.008 | 0.003 | 0.003 | 0.003 | 0.021 | 0.08 | 0.054 | 0.039 | 0.018 | 0.024 | 0.024 | 0.086 | 0.296 | 0 |
| Other C9's | 1.333 | 0.043 | 0.038 | 0.25 | 0.042 | 0.133 | 0.015 | 0.091 | 0.036 | 0.053 | 0.003 | 0.019 | 0.131 | 0.142 | 0.125 | 0.799 | 0.278 | 0.101 | 0.057 | 0.414 | 0.904 | 0 |
| n-Nonane | 0.266 | 0.013 | 0 | 0.034 | 0.011 | 0.017 | 0.005 | 0.011 | 0.009 | 0.004 | 0 | 0.007 | 0.026 | 0.127 | 0.103 | 0.021 | 0.004 | 0.025 | 0.019 | 0.132 | 0.234 | 0 |
| Other C10's | 0.708 | 0.037 | 0.011 | 0.066 | 0.058 | 0.056 | 0.011 | 0.048 | 0 | 0 | 0.007 | 0.018 | 0.189 | 0.365 | 0.302 | 0.349 | 0.18 | 0.129 | 0.085 | 0.478 | 1.015 | 0 |
| n-Decane | 0.215 | 0.007 | 0 | 0.007 | 0.012 | 0.009 | 0 | 0.048 | 0 | 0 | 0.004 | 0.004 | 0.019 | 0.181 | 0.129 | 0 | 0.005 | 0.024 | 0.011 | 0.1 | 0.193 | 0 |
| Undecanes (11) | 0.03 | 0.012 | 0.008 | 0.024 | 0.038 | 0.064 | 0.024 | 0.091 | 0 | 0 | 0.008 | 0.004 | 0.172 | 0.327 | 0.039 | 0.083 | 0.042 | 0.071 | 0.026 | 0.02 | 0.432 | 0 |
| Total | 100.27 | 99.823 | 99.999 | 99.983 | 99.916 | 99.798 | 100 | 100 | 100 | 100 | 99.979 | 99.931 | 100 | 99.984 | 99.544 | 99.999 | 99.994 | 97.8423 | 98.285 | 99.686 | 99.932 | 99.874 |
| | | | | | | | | | | | | | | | | | | | | | | |
| Specific Gravity | 1.241 | 1.333 | 1.383 | 1.421 | 0.841 | 1.056 | 0.894 | 0.814 | 0.965 | 1.235 | 1.381 | 1.365 | 1.037 | 0.737 | 1.297 | 1.052 | 1.009 | 1.252 | 1.38 | 1.282 | 1.408 | 1.126 |
| Molecular Weight (g/g-mole) | 35.71 | 38.42 | 39.85 | 40.9 | 24.26 | 30.37 | 25.8 | 23.49 | 27.84 | 35.47 | 39.79 | 39.34 | 29.9 | 21.28 | 37.4 | 30.32 | 29.11 | 36.08 | 39.74 | 36.92 | 40.49 | 32.48 |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Gas Volume Measured** | | | | | | | | | | | | | | | | | | | | | | |
| Throughput (bbl/day) | 7 | 1,000 | 75 | 1,000 | 18 | 800 | 1,200 | 6,500 | 6,000 | 4,500 | 207 | 924 | 1,298 | 2 | 3,663 | 1,204 | 1,742 | 3,680 | 1,380 | 17,000 | 10,900 | 15,000 |
| Gas-Water-Ratio (ft^3/bbl) | 0.39 | 0.94 | 1.29 | 0.49 | 1.18 | 0.44 | 1.32 | 1.2 | 0.54 | 0.59 | 1.84 | 1 | 0.34 | 0.17 | 0.66 | 1.55 | 1.21 | 0.48 | 0.81 | 0.23 | 0.03 | 0.3 |
| Cubic Feet per Year | 996 | 343,100 | 35,314 | 178,850 | 7,753 | 128,480 | 578,160 | 2,847,000 | 1,182,600 | 969,075 | 139,021 | 337,260 | 161,082 | 124 | 882,417 | 681,163 | 769,354 | 644,736 | 407,997 | 1,427,150 | 119,355 | 1,642,500 |
| Vapor Recovery System | ?? | No | No | No | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Convert Volume to Tons** | | | | | | | | | | | | | | | | | | | | | | |
| MW Sample Gas (g/g-mole) | 35.71 | 38.42 | 39.85 | 40.90 | 24.26 | 30.37 | 25.80 | 23.49 | 27.84 | 35.47 | 39.79 | 39.34 | 29.90 | 21.28 | 37.40 | 30.32 | 29.11 | 36.08 | 39.74 | 36.92 | 40.49 | 32.48 |
| Cubic Feet Year | 996 | 343,100 | 35,314 | 178,850 | 7,753 | 128,480 | 578,160 | 2,847,000 | 1,182,600 | 969,075 | 139,021 | 337,260 | 161,082 | 124 | 882,417 | 681,163 | 769,354 | 644,736 | 407,997 | 1,427,150 | 119,355 | 1,642,500 |
| Cm^3 per Ft^3 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 |
| Base Condition | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- | 4.22119E- |

| Crude Oil Produced Water | Crude Water Tanks System 1 | Crude Water Tanks System 2 | Crude Water Tanks System 3 | Crude Water Tanks System 4 | Crude Water Tanks System 5 | Crude Water Tanks System 6 | Crude Water Tanks System 7 | Crude Water Tanks System 8 | Crude Water Tanks System 9 | Crude Water Tanks System 10 | Crude Water Tanks System 11 | Crude Water Tanks System 12 | Crude Water Tanks System 13 | Crude Water Tanks System 14 | Crude Water Tanks System 15 | Crude Water Tanks System 16 | Crude Water Tanks System 17 | Crude Water Tanks System 18 | Crude Water Tanks System 19 | Crude Water Tanks System 20 | Crude Water Tanks System 21 | Crude Water Tanks System 22 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Constant (g-mole/cm^3) | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 | 05 |
| Convert grams to pounds | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 |
| Convert pounds to tons | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 |
| Tons/Year (total sample) | 0.046842676 | 17.35299374 | 1.852543845 | 9.629607462 | 0.247590801 | 5.136610692 | 19.63649988 | 88.03732041 | 43.34145005 | 45.24961724 | 7.282010547 | 17.46608313 | 6.340361116 | 0.00347648 | 43.44518515 | 27.18795723 | 29.48254177 | 30.62279175 | 21.34426303 | 69.36296444 | 6.361869049 | 70.22920147 |
| MT/Year (total sample) | 0.04249496 | 15.74237112 | 1.680599506 | 8.735832942 | 0.224610596 | 4.659854835 | 17.81393304 | 79.86611363 | 39.31870209 | 41.04976225 | 6.606128845 | 15.84496408 | 5.75187885 | 0.00315381 | 39.412809 | 24.66449991 | 26.74611199 | 27.78052937 | 19.3631897 | 62.92502286 | 5.771390519 | 63.71085988 |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Emissions Calculations** | | | | | | | | | | | | | | | | | | | | | | |
| Sample Pressure (psig) | 0 | 22 | 30 | 34 | 100 | 17 | 142 | 140 | 60 | 48 | 40 | 40 | 27 | 49 | 45 | 80 | 90 | 40 | 50 | 30 | 8 | 60 |
| Gas-Water-Ratio (ft^3/bbl) | 0.39 | 0.94 | 1.29 | 0.49 | 1.18 | 0.44 | 1.32 | 1.2 | 0.54 | 0.59 | 1.84 | 1 | 0.34 | 0.17 | 0.66 | 1.55 | 1.21 | 0.48 | 0.81 | 0.23 | 0.03 | 0.3 |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Methane** | | | | | | | | | | | | | | | | | | | | | | |
| WT% CH4 | 16.237 | 8.887 | 6.231 | 6.725 | 45.384 | 26.843 | 41.456 | 50.069 | 31.522 | 11.236 | 5.943 | 7.422 | 28.501 | 62.803 | 10.539 | 27.37 | 29.774 | 12.875 | 5.829 | 12.616 | 8.972 | 20.053 |
| WT Fraction CH4 | 0.16237 | 0.08887 | 0.06231 | 0.06725 | 0.45384 | 0.26843 | 0.41456 | 0.50069 | 0.31522 | 0.11236 | 0.05943 | 0.07422 | 0.28501 | 0.62803 | 0.10539 | 0.2737 | 0.29774 | 0.12875 | 0.05829 | 0.12616 | 0.08972 | 0.20053 |
| MT/Year CO2e (uncontrolled) | 0.145 | 29.380 | 2.199 | 12.337 | 2.141 | 26.268 | 155.084 | 839.751 | 260.275 | 96.859 | 8.245 | 24.696 | 34.426 | 0.042 | 87.228 | 141.764 | 167.231 | 75.112 | 23.702 | 166.711 | 10.874 | 268.295 |
| MT/Barrel (uncontrolled) | 0.00006 | 0.00008 | 0.00008 | 0.00003 | 0.00033 | 0.00009 | 0.00035 | 0.00035 | 0.00012 | 0.00006 | 0.00011 | 0.00007 | 0.00007 | 0.00006 | 0.00007 | 0.00032 | 0.00026 | 0.00006 | 0.00005 | 0.00003 | 0.00000 | 0.00005 |
| MT/Year CO2e (controlled 95%) | 0.007 | 1.469 | 0.110 | 0.617 | 0.107 | 1.313 | 7.754 | 41.988 | 13.014 | 4.843 | 0.412 | 1.235 | 1.721 | 0.002 | 4.361 | 7.088 | 8.362 | 3.756 | 1.185 | 8.336 | 0.544 | 13.415 |
| MT/Barrel (controlled 95%) | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00002 | 0.00000 | 0.00002 | 0.00002 | 0.00001 | 0.00000 | 0.00001 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00002 | 0.00001 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Carbon Dioxide** | | | | | | | | | | | | | | | | | | | | | | |
| WT% | 46.99 | 88.82 | 91.39 | 84.15 | 24.62 | 15.00 | 47.36 | 42.83 | 44.87 | 23.60 | 92.32 | 88.75 | 54.98 | 31.61 | 86.70 | 63.26 | 65.57 | 81.42 | 84.86 | 80.07 | 77.52 | 78.12 |

| **Crude Oil Produced Water** | **Crude Water Tanks System 1** | **Crude Water Tanks System 2** | **Crude Water Tanks System 3** | **Crude Water Tanks System 4** | **Crude Water Tanks System 5** | **Crude Water Tanks System 6** | **Crude Water Tanks System 7** | **Crude Water Tanks System 8** | **Crude Water Tanks System 9** | **Crude Water Tanks System 10** | **Crude Water Tanks System 11** | **Crude Water Tanks System 12** | **Crude Water Tanks System 13** | **Crude Water Tanks System 14** | **Crude Water Tanks System 15** | **Crude Water Tanks System 16** | **Crude Water Tanks System 17** | **Crude Water Tanks System 18** | **Crude Water Tanks System 19** | **Crude Water Tanks System 20** | **Crude Water Tanks System 21** | **Crude Water Tanks System 22** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $CO_2$ | 7 | | 4 | 2 | 1 | 9 | 3 | 9 | 4 | 1 | 5 | 7 | 7 | 3 | 5 | 6 | 8 | 1 | 9 | 3 | | 2 |
| WT Fraction $CO_2$ | 0.46997 | 0.8882 | 0.91394 | 0.84152 | 0.24621 | 0.15009 | 0.47363 | 0.42839 | 0.44874 | 0.23601 | 0.92325 | 0.88757 | 0.54987 | 0.31613 | 0.86705 | 0.63266 | 0.65578 | 0.81421 | 0.84869 | 0.80073 | 0.7752 | 0.78122 |
| MT/Year $CO_2$ (uncontrolled) | 0.020 | 13.982 | 1.536 | 7.351 | 0.055 | 0.699 | 8.437 | 34.214 | 17.644 | 9.688 | 6.099 | 14.064 | 3.163 | 0.001 | 34.173 | 15.604 | 17.540 | 22.619 | 16.433 | 50.386 | 4.474 | 49.772 |
| MT/Barrel (uncontrolled) | 0.00000782 | 0.00003831 | 0.00005611 | 0.00002014 | 0.00000842 | 0.00000240 | 0.00001926 | 0.00001442 | 0.00000806 | 0.00000590 | 0.00008072 | 0.00004170 | 0.00000668 | 0.00000137 | 0.00002556 | 0.00003551 | 0.00002759 | 0.00001684 | 0.00003263 | 0.00000812 | 0.00000112 | 0.00000909 |
| MT/Year $CO_2e$ (controlled 95%) | 0.001 | 0.699 | 0.077 | 0.368 | 0.003 | 0.035 | 0.422 | 1.711 | 0.882 | 0.484 | 0.305 | 0.703 | 0.158 | 0.000 | 1.709 | 0.780 | 0.877 | 1.131 | 0.822 | 2.519 | 0.224 | 2.489 |
| MT/Barrel (controlled 95%) | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| | | | | | | | | | | | | | | | | | | | | | | |
| **$MTCO_2e$/Barrel Uncontrolled** | **0.0001** | **0.0001** | **0.0001** | **0.0001** | **0.0003** | **0.0001** | **0.0004** | **0.0004** | **0.0001** | **0.0001** | **0.0002** | **0.0001** | **0.0001** | **0.0001** | **0.0001** | **0.0004** | **0.0003** | **0.0001** | **0.0001** | **0.0000** | **0.0000** | **0.0001** |
| **$MTCO_2e$/Barrel Controlled 95%** | **0.00000** | **0.00001** | **0.00001** | **0.00000** | **0.00002** | **0.00000** | **0.00002** | **0.00002** | **0.00001** | **0.00000** | **0.00001** | **0.00001** | **0.00000** | **0.00000** | **0.00000** | **0.00002** | **0.00001** | **0.00000** | **0.00000** | **0.00000** | **0.00000** | **0.00000** |
| | | | | | | | | | | | | | | | | | | | | | | |
| **VOCs Measured** | | | | | | | | | | | | | | | | | | | | | | |
| WT% C3-C9 | 24.474 | 1.984 | 1.591 | 8.622 | 18.49 | 43.589 | 8.895 | 3.892 | 11.148 | 41.685 | 0.807 | 2.996 | 13.697 | 4.194 | 1.266 | 7.131 | 3.167 | 3.215 | 6.104 | 5.919 | 11.129 | 0.581 |
| WT Fraction C3-C9 | 0.24474 | 0.01984 | 0.01591 | 0.08622 | 0.1849 | 0.43589 | 0.08895 | 0.03892 | 0.11148 | 0.41685 | 0.00807 | 0.02996 | 0.13697 | 0.04194 | 0.01266 | 0.07131 | 0.03167 | 0.03215 | 0.06104 | 0.05919 | 0.11129 | 0.00581 |
| Tons/Year C3-C9 (uncontrolled) | 0.011 | 0.344 | 0.029 | 0.830 | 0.046 | 2.239 | 1.747 | 3.426 | 4.832 | 18.862 | 0.059 | 0.523 | 0.868 | 0.000 | 0.550 | 1.939 | 0.934 | 0.985 | 1.303 | 4.106 | 0.708 | 0.408 |
| **Tons VOC/BBL Uncontrolled** | 0.000004 | 0.000001 | 0.000001 | 0.000002 | 0.000007 | 0.000008 | 0.000004 | 0.000001 | 0.000002 | 0.000011 | 0.000001 | 0.000002 | 0.000002 | 0.000000 | 0.000000 | 0.000004 | 0.000001 | 0.000001 | 0.000003 | 0.000001 | 0.000000 | 0.000000 |
| Tons/Year (controlled) | 0.001 | 0.017 | 0.001 | 0.042 | 0.002 | 0.112 | 0.087 | 0.171 | 0.242 | 0.943 | 0.003 | 0.026 | 0.043 | 0.000 | 0.028 | 0.097 | 0.047 | 0.049 | 0.065 | 0.205 | 0.035 | 0.020 |
| **Tons VOC/BBL Controlled** | 0.0000002 | 0.0000000 | 0.0000001 | 0.0000001 | 0.0000003 | 0.0000004 | 0.0000002 | 0.0000001 | 0.0000001 | 0.000001 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 |

| Crude Oil Produced Water | Crude Water Tanks System 1 | Crude Water Tanks System 2 | Crude Water Tanks System 3 | Crude Water Tanks System 4 | Crude Water Tanks System 5 | Crude Water Tanks System 6 | Crude Water Tanks System 7 | Crude Water Tanks System 8 | Crude Water Tanks System 9 | Crude Water Tanks System 10 | Crude Water Tanks System 11 | Crude Water Tanks System 12 | Crude Water Tanks System 13 | Crude Water Tanks System 14 | Crude Water Tanks System 15 | Crude Water Tanks System 16 | Crude Water Tanks System 17 | Crude Water Tanks System 18 | Crude Water Tanks System 19 | Crude Water Tanks System 20 | Crude Water Tanks System 21 | Crude Water Tanks System 22 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | |

## Table D-13: ARB Fullerton DG Water Data

| Dry Gas Produced Water | Dry Gas Water Tanks System 23 | Dry Gas Water Tanks System 24 | Dry Gas Water Tanks System 25 | Dry Gas Water Tanks System 26 | Dry Gas Water Tanks System 27 | Dry Gas Water Tanks System 28 | Dry Gas Water Tanks System 29 | Dry Gas Water Tanks System 30 | Dry Gas Water Tanks System 31 | Dry Gas Water Tanks System 32 | Dry Gas Water Tanks System 33 | Dry Gas Water Tanks System 34 | Dry Gas Water Tanks System 35 | Dry Gas Water Tanks System 36 | Dry Gas Water Tanks System 37 | Dry Gas Water Tanks System 38 | Dry Gas Water Tanks System 39 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Water Sample Association | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas |
| Date Sampled | 8/9/2010 | 8/9/2010 | 8/9/2010 | 8/9/2010 | 8/9/2010 | 8/9/2010 | 11/11/2010 | 11/11/2010 | 11/11/2010 | 11/11/2010 | 11/11/2010 | 11/11/2010 | 8/10/2010 | 8/10/2010 | 8/10/2010 | 3/30/2011 | 3/30/2011 |
| Date Analyzed | 8/24/2010 | 8/24/2010 | 8/24/2010 | 8/25/2010 | 8/25/2010 | 8/25/2010 | 11/22/2010 | 11/22/2010 | 11/22/2010 | 11/22/2010 | 11/22/2010 | 11/22/2010 | 8/24/2010 | 8/24/2010 | 8/24/2010 | 4/8/2011 | 4/8/2011 |
| Job Number | J04537.501 | J04537.401 | J04537.001 | J04537.201 | J04537.301 | J04537.101 | JO6156 | JO6152 | JO6154 | JO6155 | JO6157 | J06153 | J04538.201 | J04538.001 | J04538.501 | J11871 | J11871 |
| | | | | | | | | | | | | | | | | | |
| Sample Pressure (psig) | 29 | 117 | 108 | 120 | 185 | 117 | 820 | 805 | 822 | 810 | 820 | 800 | 39 | 65 | 780 | 1450 | 1450 |
| Sample Temperature (deg F) | 82 | 90 | 81 | 84 | 80 | 82 | 62 | 66 | 75 | 70 | 90 | 62 | 79 | 63 | 90 | 93 | 93 |
| Gas-Water-Ratio (ft^3/bbl) | 0.35 | 1.33 | 0.87 | 1.14 | 1.93 | 1.41 | 5.4 | 6.5 | 5.2 | 6.4 | 6.5 | 3.6 | 0.53 | 1.25 | 8.46 | 5.93 | 8.68 |
| Base Conditions (Flashed to) | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.73 PSI & 60°F | 14.65 PSI & 60°F | 14.65 PSI & 60°F |
| Throughput (bbl/day) | 41 | 5 | 8 | 14 | 20 | 6 | 1 | 4 | 24 | 1 | 27 | 7 | 5 | 90 | 16 | 1 | 1 |
| | | | | | | | | | | | | | | | | | |
| **Chromatograph Compounds** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** | **Wt %** |
| Nitrogen | 0 | 12.239 | 0 | 3.447 | 0.827 | 8.282 | 4.42 | 1.216 | 0.606 | 3.759 | 0.21 | 5.399 | 0.181 | 4.56 | 0.672 | 0.397 | 0.786 |
| Carbon Dioxide | 11.844 | 5.5 | 5.863 | 5.28 | 3.408 | 4.519 | 2.652 | 1.266 | 1.815 | 1.633 | 0.859 | 1.712 | 28.4 | 11.9 | 4.493 | 26.42 | 30.182 |
| Methane | 80.768 | 69.614 | 84.658 | 84.721 | 92.617 | 84.846 | 92.309 | 97.064 | 97.065 | 94.048 | 98.489 | 91.965 | 46.024 | 61.623 | 54.194 | 65.628 | 64.48 |
| Ethane | 1.08 | 1.734 | 0.906 | 1.035 | 0.578 | 0.325 | 0.348 | 0.265 | 0.212 | 0.365 | 0.169 | 0.472 | 5.91 | 4.591 | 8.805 | 5.597 | 2.697 |
| Propane | 0.648 | 0.435 | 0.237 | 0.211 | 0.152 | 0 | 0.018 | 0.013 | 0.009 | 0.02 | 0.003 | 0.087 | 3.014 | 2.168 | 9.552 | 1.054 | 0.263 |
| Isobutane | 0.564 | 0.118 | 0.129 | 0.085 | 0.052 | 0 | 0.008 | 0.004 | 0.003 | 0.004 | 0.001 | 0.021 | 0.691 | 0.556 | 3.298 | 0.072 | 0.031 |
| n-Butane | 0.555 | 0.201 | 0.196 | 0.186 | 0.155 | 0 | 0.008 | 0.003 | 0.016 | 0.009 | 0.008 | 0.032 | 1.256 | 0.918 | 5.11 | 0.046 | 0.059 |
| 2,2 Dimethylpropane | 0 | 0 | 0.124 | 0 | 0.06 | 0 | 0.002 | 0 | 0.02 | 0.005 | 0.005 | 0 | 0.08 | 0.013 | 0.115 | 0.007 | 0.024 |
| Isopentane | 0.509 | 0.264 | 0.152 | 0.065 | 0.09 | 0 | 0.005 | 0.011 | 0.007 | 0.007 | 0.003 | 0.03 | 0.62 | 0.526 | 2.283 | 0.014 | 0.035 |
| n-Pentane | 0.665 | 0.165 | 0.02 | 0 | 0.107 | 0 | 0.007 | 0.003 | 0.009 | 0.009 | 0.001 | 0.019 | 0.388 | 0.496 | 1.827 | 0.014 | 0.045 |

| Dry Gas Produced Water | Dry Gas Water Tanks System 23 | Dry Gas Water Tanks System 24 | Dry Gas Water Tanks System 25 | Dry Gas Water Tanks System 26 | Dry Gas Water Tanks System 27 | Dry Gas Water Tanks System 28 | Dry Gas Water Tanks System 29 | Dry Gas Water Tanks System 30 | Dry Gas Water Tanks System 31 | Dry Gas Water Tanks System 32 | Dry Gas Water Tanks System 33 | Dry Gas Water Tanks System 34 | Dry Gas Water Tanks System 35 | Dry Gas Water Tanks System 36 | Dry Gas Water Tanks System 37 | Dry Gas Water Tanks System 38 | Dry Gas Water Tanks System 39 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2,2 Dimethylbutane | 0 | 0.004 | 0.024 | 0.01 | 0.005 | 0 | 0.001 | 0 | 0.001 | 0.004 | 0 | 0.001 | 0.024 | 0.032 | 0.086 | 0 | 0.004 |
| Cyclopentane | 0.011 | 0.043 | 0.039 | 0.035 | 0.021 | 0.004 | 0.004 | 0.002 | 0.001 | 0.001 | 0 | 0.009 | 0.17 | 0.156 | 0 | 0.014 | 0.003 |
| 2,3 Dimethylbutane | 0.023 | 0.105 | 0.043 | 0.029 | 0.01 | 0.025 | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0.002 | 0.034 | 0.052 | 0.413 | 0.004 | 0.008 |
| 2 Methylpentane | 0.178 | 0.838 | 0.272 | 0.223 | 0.066 | 0.177 | 0.006 | 0.004 | 0.008 | 0.006 | 0.006 | 0.011 | 0.295 | 0.332 | 0.555 | 0.051 | 0.092 |
| 3 Methylpentane | 0.271 | 1.176 | 0.363 | 0.296 | 0.066 | 0.237 | 0.004 | 0.004 | 0.009 | 0.005 | 0.008 | 0.005 | 0.267 | 0.296 | 0.343 | 0.085 | 0.138 |
| n-Hexane | 0.771 | 3.329 | 1.245 | 0.998 | 0.174 | 0.582 | 0.011 | 0.009 | 0.028 | 0.02 | 0.026 | 0.011 | 0.727 | 0.705 | 0.67 | 0.293 | 0.451 |
| Methylcyclopentane | 0.26 | 0.994 | 0.471 | 0.383 | 0.115 | 0.154 | 0.015 | 0.012 | 0.015 | 0.007 | 0.006 | 0.033 | 0.566 | 0.77 | 1.109 | 0.07 | 0.106 |
| Benzene | 0.106 | 0.696 | 0.835 | 0.237 | 0.116 | 0.045 | 0.011 | 0.012 | 0.004 | 0.002 | 0.003 | 0.022 | 2.278 | 0.849 | 0.743 | 0.012 | 0.011 |
| Cyclohexane | 0 | 0.715 | 0.433 | 0.393 | 0.11 | 0.01 | 0.003 | 0.001 | 0.01 | 0.006 | 0.001 | 0.007 | 0.753 | 0.856 | 1.076 | 0.091 | 0.122 |
| 2-Methylhexane | 0.016 | 0.036 | 0.05 | 0.045 | 0.018 | 0.006 | 0.002 | 0.001 | 0.002 | 0.002 | 0 | 0.002 | 0.108 | 0.144 | 0.147 | 0.005 | 0.01 |
| 3-Methylhexane | 0.016 | 0.031 | 0.05 | 0.051 | 0.018 | 0.006 | 0.003 | 0.001 | 0.002 | 0.001 | 0 | 0.003 | 0.112 | 0.158 | 0.147 | 0.005 | 0.01 |
| 2,2,4 Trimethylpentane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other C7's | 0.339 | 0.283 | 0.242 | 0.223 | 0.106 | 0.176 | 0.023 | 0.019 | 0.017 | 0.008 | 0.008 | 0.04 | 0.347 | 0.737 | 0.72 | 0.068 | 0.337 |
| n-Heptane | 0.038 | 0.061 | 0.111 | 0.096 | 0.048 | 0.017 | 0.007 | 0.004 | 0.007 | 0.004 | 0.001 | 0.007 | 0.231 | 0.358 | 0.299 | 0.005 | 0.01 |
| Methylcyclohexane | 0.085 | 0.185 | 0.321 | 0.282 | 0.175 | 0.062 | 0.02 | 0.012 | 0.003 | 0.004 | 0.002 | 0.021 | 0.82 | 1.546 | 1.252 | 0.01 | 0.014 |
| Toluene | 0.27 | 0.324 | 0.811 | 0.389 | 0.24 | 0.1 | 0.022 | 0.01 | 0.008 | 0.004 | 0.005 | 0.008 | 3.516 | 1.52 | 0.773 | 0.014 | 0.013 |
| Other C8's | 0.096 | 0.252 | 0.421 | 0.322 | 0.183 | 0.076 | 0.028 | 0.026 | 0.038 | 0.019 | 0.003 | 0.041 | 0.632 | 1.408 | 0.681 | 0.016 | 0.032 |
| n-Octane | 0.043 | 0.058 | 0.095 | 0.071 | 0.034 | 0.013 | 0.004 | 0.002 | 0.005 | 0.002 | 0.002 | 0.003 | 0.123 | 0.276 | 0.099 | 0 | 0.006 |
| Ethylbenzene | 0.029 | 0.032 | 0.094 | 0.042 | 0.025 | 0.012 | 0.003 | 0.003 | 0.003 | 0.002 | 0.001 | 0.003 | 0.177 | 0.113 | 0.028 | 0 | 0 |
| M & P Xylenes | 0.196 | 0.13 | 0.459 | 0.203 | 0.101 | 0.067 | 0.01 | 0.004 | 0.005 | 0.002 | 0.005 | 0.003 | 1.039 | 0.523 | 0.138 | 0.005 | 0.005 |
| O-Xylene | 0.052 | 0.032 | 0.106 | 0.054 | 0.025 | 0.018 | 0.003 | 0.001 | 0.002 | 0.001 | 0.002 | 0.001 | 0.237 | 0.109 | 0.028 | 0 | 0 |
| Other C9's | 0.068 | 0.206 | 0.336 | 0.284 | 0.12 | 0.043 | 0.014 | 0.016 | 0.023 | 0.02 | 0.007 | 0.021 | 0.311 | 0.886 | 0.229 | 0 | 0.006 |
| n-Nonane | 0.056 | 0.046 | 0.121 | 0.058 | 0.023 | 0.015 | 0.002 | 0.001 | 0.004 | 0.001 | 0.006 | 0.001 | 0.077 | 0.149 | 0.022 | 0 | 0 |
| Other C10's | 0.268 | 0.101 | 0.438 | 0.151 | 0.092 | 0.081 | 0.009 | 0.008 | 0.014 | 0.013 | 0.035 | 0.007 | 0.365 | 0.519 | 0.067 | 0 | 0 |

| Dry Gas Produced Water | Dry Gas Water Tanks System 23 | Dry Gas Water Tanks System 24 | Dry Gas Water Tanks System 25 | Dry Gas Water Tanks System 26 | Dry Gas Water Tanks System 27 | Dry Gas Water Tanks System 28 | Dry Gas Water Tanks System 29 | Dry Gas Water Tanks System 30 | Dry Gas Water Tanks System 31 | Dry Gas Water Tanks System 32 | Dry Gas Water Tanks System 33 | Dry Gas Water Tanks System 34 | Dry Gas Water Tanks System 35 | Dry Gas Water Tanks System 36 | Dry Gas Water Tanks System 37 | Dry Gas Water Tanks System 38 | Dry Gas Water Tanks System 39 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| n-Decane | 0.039 | 0.022 | 0.055 | 0.032 | 0.008 | 0.008 | 0.001 | 0.001 | 0.002 | 0.001 | 0.034 | 0 | 0.028 | 0.04 | 0.006 | 0 | 0 |
| Undecanes (11) | 0.136 | 0.031 | 0.28 | 0.063 | 0.055 | 0.094 | 0.016 | 0.001 | 0.026 | 0.005 | 0.09 | 0.001 | 0.199 | 0.113 | 0.02 | 0 | 0 |
| Total | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 99.998 | 100 | 99.997 | 99.98 |
| | | | | | | | | | | | | | | | | | |
| Specific Gravity | 0.638 | 0.68 | 0.625 | 0.616 | 0.583 | 0.605 | 0.608 | 0.579 | 0.585 | 0.593 | 0.575 | 0.606 | 0.872 | 0.746 | 0.802 | 0.703 | 0.714 |
| Molecular Weight (g/g-mole) | 18.43 | 19.64 | 18.06 | 17.79 | 16.86 | 17.48 | 17.58 | 16.73 | 16.9 | 17.15 | 16.62 | 17.52 | 25.13 | 21.52 | 23.14 | 20.3 | 20.63 |
| | | | | | | | | | | | | | | | | | |
| **Gas Volume Measured** | | | | | | | | | | | | | | | | | |
| Throughput (bbl/day) | 41 | 5 | 8 | 14 | 20 | 6 | 1 | 4 | 24 | 1 | 27 | 7 | 5 | 90 | 16 | 1 | 1 |
| Gas-Water-Ratio (ft^3/bbl) | 0.35 | 1.33 | 0.87 | 1.14 | 1.93 | 1.41 | 5.4 | 6.5 | 5.2 | 6.4 | 6.5 | 3.6 | 0.53 | 1.25 | 8.46 | 5.93 | 8.68 |
| Cubic Feet per Year | 5,238 | 2,427 | 2,540 | 5,825 | 14,089 | 3,088 | 1,971 | 9,490 | 45,552 | 2,336 | 64,058 | 9,198 | 967 | 41,063 | 49,406 | 2,164 | 3,168 |
| Vapor Recovery System | No | No | No | No | No | No | No | No | No | No | No | No | No | No | No | No | No |
| | | | | | | | | | | | | | | | | | |
| **Convert Volume to Tons** | | | | | | | | | | | | | | | | | |
| MW Sample Gas (g/g-mole) | 18.43 | 19.64 | 18.06 | 17.79 | 16.86 | 17.48 | 17.58 | 16.73 | 16.90 | 17.15 | 16.62 | 17.52 | 25.13 | 21.52 | 23.14 | 20.30 | 20.63 |
| Cubic Feet Year | 5,238 | 2,427 | 2,540 | 5,825 | 14,089 | 3,088 | 1,971 | 9,490 | 45,552 | 2,336 | 64,058 | 9,198 | 967 | 41,063 | 49,406 | 2,164 | 3,168 |
| Cm^3 per Ft^3 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 | 28317 |
| Base Condition Constant (g-mole/cm^3) | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 | 4.22119E-05 |
| Convert grams to pounds | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 | 0.002202643 |
| Convert pounds to tons | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 | 0.00050 |
| Tons/Year (total sample) | 0.127076847 | 0.062755577 | 0.060397113 | 0.136426278 | 0.312704457 | 0.071056038 | 0.045614385 | 0.209005871 | 1.013422369 | 0.05273917 | 1.401513664 | 0.212140622 | 0.031998348 | 1.163279261 | 1.505022166 | 0.057841551 | 0.086041535 |
| MT/Year (total | 0.115282177 | 0.056930902 | 0.054791339 | 0.123763838 | 0.283680711 | 0.064460953 | 0.041380674 | 0.189606936 | 0.919361308 | 0.047844171 | 1.271431809 | 0.192450735 | 0.029028413 | 1.055309194 | 1.365333143 | 0.052472972 | 0.078055567 |

| Dry Gas Produced Water | Dry Gas Water Tanks System 23 | Dry Gas Water Tanks System 24 | Dry Gas Water Tanks System 25 | Dry Gas Water Tanks System 26 | Dry Gas Water Tanks System 27 | Dry Gas Water Tanks System 28 | Dry Gas Water Tanks System 29 | Dry Gas Water Tanks System 30 | Dry Gas Water Tanks System 31 | Dry Gas Water Tanks System 32 | Dry Gas Water Tanks System 33 | Dry Gas Water Tanks System 34 | Dry Gas Water Tanks System 35 | Dry Gas Water Tanks System 36 | Dry Gas Water Tanks System 37 | Dry Gas Water Tanks System 38 | Dry Gas Water Tanks System 39 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sample) | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | |
| **Emissions Calculations** | | | | | | | | | | | | | | | | | |
| Sample Pressure (psi) | 29 | 117 | 108 | 120 | 185 | 117 | 820 | 805 | 822 | 810 | 820 | 800 | 39 | 65 | 780 | 1450 | 1450 |
| Gas Water Ratio | 0.35 | 1.33 | 0.87 | 1.14 | 1.93 | 1.41 | 5.4 | 6.5 | 5.2 | 6.4 | 6.5 | 3.6 | 0.53 | 1.25 | 8.46 | 5.93 | 8.68 |
| | | | | | | | | | | | | | | | | | |
| **Methane** | | | | | | | | | | | | | | | | | |
| WT% CH4 | 80.768 | 69.614 | 84.658 | 84.721 | 92.617 | 84.846 | 92.309 | 97.064 | 97.065 | 94.048 | 98.489 | 91.965 | 46.024 | 61.623 | 54.194 | 65.628 | 64.48 |
| WT Fraction CH4 | 0.80768 | 0.69614 | 0.84658 | 0.84721 | 0.92617 | 0.84846 | 0.92309 | 0.97064 | 0.97065 | 0.94048 | 0.98489 | 0.91965 | 0.46024 | 0.61623 | 0.54194 | 0.65628 | 0.6448 |
| MT/Year CO2e (uncontrolled) | 1.955 | 0.832 | 0.974 | 2.202 | 5.517 | 1.149 | 0.802 | 3.865 | 18.740 | 0.945 | 26.297 | 3.717 | 0.281 | 13.657 | 15.539 | 0.723 | 1.057 |
| MT/Barrel (uncontrolled) | 0.00013 | 0.00046 | 0.00033 | 0.00043 | 0.00076 | 0.00052 | 0.00220 | 0.00265 | 0.00214 | 0.00259 | 0.00267 | 0.00145 | 0.00015 | 0.00042 | 0.00266 | 0.00198 | 0.00290 |
| MT/Year CO2e (controlled 95%) | 0.098 | 0.042 | 0.049 | 0.110 | 0.276 | 0.057 | 0.040 | 0.193 | 0.937 | 0.047 | 1.315 | 0.186 | 0.014 | 0.683 | 0.777 | 0.036 | 0.053 |
| MT/Barrel (controlled 95%) | 0.00001 | 0.00002 | 0.00002 | 0.00002 | 0.00004 | 0.00003 | 0.00011 | 0.00013 | 0.00011 | 0.00013 | 0.00013 | 0.00007 | 0.00001 | 0.00002 | 0.00013 | 0.00010 | 0.00014 |
| | | | | | | | | | | | | | | | | | |
| **Carbon Dioxide** | | | | | | | | | | | | | | | | | |
| WT% CO2 | 11.844 | 5.5 | 5.863 | 5.28 | 3.408 | 4.519 | 2.652 | 1.266 | 1.815 | 1.633 | 0.859 | 1.712 | 28.4 | 11.9 | 4.493 | 26.42 | 30.182 |
| WT Fraction CO2 | 0.11844 | 0.055 | 0.05863 | 0.0528 | 0.03408 | 0.04519 | 0.02652 | 0.01266 | 0.01815 | 0.01633 | 0.00859 | 0.01712 | 0.284 | 0.119 | 0.04493 | 0.2642 | 0.30182 |
| MT/Year CO2 (uncontrolled) | 0.014 | 0.003 | 0.003 | 0.007 | 0.010 | 0.003 | 0.001 | 0.002 | 0.017 | 0.001 | 0.011 | 0.003 | 0.008 | 0.126 | 0.061 | 0.014 | 0.024 |
| MT/Barrel (uncontrolled) | 0.00000091 | 0.00000172 | 0.00000110 | 0.00000128 | 0.00000132 | 0.00000133 | 0.00000301 | 0.00000164 | 0.00000190 | 0.00000214 | 0.00000111 | 0.00000129 | 0.00000452 | 0.00000382 | 0.00001050 | 0.00003798 | 0.00006454 |
| MT/Year CO2e (controlled 95%) | 0.001 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.001 | 0.000 | 0.000 | 0.006 | 0.003 | 0.001 | 0.001 |
| MT/Barrel (controlled 95%) | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |

| Dry Gas Produced Water | Dry Gas Water Tanks System 23 | Dry Gas Water Tanks System 24 | Dry Gas Water Tanks System 25 | Dry Gas Water Tanks System 26 | Dry Gas Water Tanks System 27 | Dry Gas Water Tanks System 28 | Dry Gas Water Tanks System 29 | Dry Gas Water Tanks System 30 | Dry Gas Water Tanks System 31 | Dry Gas Water Tanks System 32 | Dry Gas Water Tanks System 33 | Dry Gas Water Tanks System 34 | Dry Gas Water Tanks System 35 | Dry Gas Water Tanks System 36 | Dry Gas Water Tanks System 37 | Dry Gas Water Tanks System 38 | Dry Gas Water Tanks System 39 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | |
| **MTCO2e/Barrel Uncontrolled** | **0.00013** | **0.00046** | **0.00033** | **0.00043** | **0.00076** | **0.00053** | **0.00220** | **0.00265** | **0.00214** | **0.00259** | **0.00267** | **0.00146** | **0.00016** | **0.00042** | **0.00267** | **0.00202** | **0.00296** |
| **MTCO2e/Barrel Controlled 95%** | **0.00001** | **0.00002** | **0.00002** | **0.00002** | **0.00004** | **0.00003** | **0.00011** | **0.00013** | **0.00011** | **0.00013** | **0.00013** | **0.00007** | **0.00001** | **0.00002** | **0.00013** | **0.00010** | **0.00015** |
| | | | | | | | | | | | | | | | | | |
| **VOCs Measured** | | | | | | | | | | | | | | | | | |
| WT% C3-C9 | 5.809 | 10.713 | 7.679 | 5.213 | 2.392 | 1.83 | 0.243 | 0.178 | 0.256 | 0.175 | 0.108 | 0.443 | 18.816 | 16.503 | 31.721 | 1.955 | 1.835 |
| WT Fraction C3-C9 | 0.05809 | 0.10713 | 0.07679 | 0.05213 | 0.02392 | 0.0183 | 0.00243 | 0.00178 | 0.00256 | 0.00175 | 0.00108 | 0.00443 | 0.18816 | 0.16503 | 0.31721 | 0.01955 | 0.01835 |
| Tons/Year (uncontrolled) | 0.007 | 0.007 | 0.005 | 0.007 | 0.007 | 0.001 | 0.000 | 0.000 | 0.003 | 0.000 | 0.002 | 0.001 | 0.006 | 0.192 | 0.477 | 0.001 | 0.002 |
| **Tons VOC/Barrel Uncontrolled** | 0.0000004933 | 0.0000036838 | 0.0000015883 | 0.0000013918 | 0.0000010246 | 0.0000005938 | 0.0000003037 | 0.0000002548 | 0.0000002962 | 0.0000002529 | 0.0000001536 | 0.0000003678 | 0.0000032991 | 0.0000058440 | 0.0000817480 | 0.0000030981 | 0.0000043256 |
| Tons/Year (controlled) | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.010 | 0.024 | 0.000 | 0.000 |
| **Tons VOC/Barrel Controlled** | 0.0000000247 | 0.0000001842 | 0.0000000794 | 0.0000000696 | 0.0000000512 | 0.0000000297 | 0.0000000152 | 0.0000000127 | 0.0000000148 | 0.0000000126 | 0.0000000077 | 0.0000000184 | 0.0000001650 | 0.0000002922 | 0.0000040874 | 0.0000001549 | 0.0000002163 |
| | | | | | | | | | | | | | | | | | |

## Table D-14: WSPA Dataset #1 Crude Oil Flash Samples

| | Crude Oil Flash Sample | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Crude Throughput (bbl)** | **Reid Vapor Pressure (psia)** | **Crude Oil API Gravity** | **Flash Gas MW (g/g-mole)** | **GOR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 1 | 2,260,581 | 2.1 | 17 | 33.08 | 2.715 | 24.92 | 15.08 | 59.99 | 0.01 | 0 |
| Tank Farm 2 | 1,249,560 | 0.6 | 17 | 31.43 | 1.123 | 27.71 | 30.55 | 41.7 | 0 | 0.04 |
| Tank Farm 3 | 9,414,322 | 1.7 | 18 | 23.55 | 7.069 | 51.57 | 12.51 | 35.92 | 0 | 0 |
| Tank Farm 4 | 230,900 | 5.1 | 31.2 | 34.17 | 14.471 | 19.21 | 0.25 | 80.53 | 0 | 0.01 |
| Tank Farm 5 | 69,133 | 1.8 | 21.2 | 27.22 | 4.442 | 40.62 | 5.15 | 54.23 | 0 | 0 |
| Tank Farm 6 | 197,040 | 4.2 | 33.2 | 43.55 | 6.398 | 7.86 | 7.87 | 84.27 | 0 | 0 |
| Tank Farm 7 | 100,103 | 1 | 32.8 | 28.17 | 10.768 | 21.54 | 0.69 | 77.76 | 0 | 0.01 |
| Tank Farm 8 | 48,779 | 1.6 | 29.6 | 25.44 | 6.37 | 32.4 | 9.51 | 58.09 | 0 | 0 |
| Tank Farm 9 | 6,198 | 0.6 | 21.8 | 22.71 | 2.28 | 44.13 | 2.78 | 53.09 | 0 | 0 |
| Tank Farm 10 | 2,429,842 | 0.1 | 11.8 | 25.03 | 1.931 | 42.88 | 53.92 | 3.2 | 0 | 0 |
| Tank Farm 11 | 8,747 | 1.8 | 20.8 | 43.78 | 0.853 | 11.56 | 26.1 | 62.34 | 0 | 0 |
| Tank Farm 12 | 292,695 | 0.7 | 13.1 | 28.53 | 2.231 | 31.27 | 63.26 | 5.47 | 0 | 0 |
| Tank Farm 13 | 7,835 | 2.4 | 24.8 | 31.92 | 10.891 | 18.03 | 25.32 | 56.65 | 0 | 0 |
| Tank Farm 14 | 73,541 | 8.6 | 34.6 | 44.75 | 16.059 | 5.4 | 0.29 | 94.31 | 0 | 0 |
| Tank Farm 15 | 14,743 | 2.9 | 33.2 | 35.69 | 10.801 | 17.77 | 0.25 | 81.97 | 0 | 0.01 |
| Tank Farm 16 | 924,983 | 6.5 | 25.8 | 38.65 | 8.516 | 14.66 | 0.3 | 85.04 | 0 | 0 |
| Tank Farm 17 | 176,209 | 2.7 | 28.2 | 34.39 | 11.131 | 18.8 | 6.52 | 74.68 | 0 | 0 |
| Tank Farm 18 | 45,395 | 3.7 | 20.6 | 43.22 | 3.196 | 5.56 | 0.48 | 93.94 | 0 | 0.02 |
| Tank Farm 19 | 54,139 | 2.6 | 26.1 | 26.28 | 16.448 | 39.24 | 16.46 | 44.3 | 0 | 0 |
| Tank Farm 20 | 33,174 | 2.6 | 26.5 | 32.46 | 8.885 | 26.69 | 7.38 | 65.91 | 0 | 0.02 |
| Tank Farm 21 | 57,643 | 0.4 | 16.4 | 33.15 | 1.948 | 20.54 | 58.92 | 20.54 | 0 | 0 |
| Tank Farm 22 | 2,517 | 2.3 | 24.6 | 26.26 | 12.098 | 35.6 | 36.05 | 28.35 | 0 | 0 |

## Table D-15: WSPA Dataset #1 Produced Water Flash Sample

| | Produced Water Flash Sample | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Water Throughput (bbl)** | **Flash Gas MW (g/g-mole)** | **GWR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 1 | 109,398,086 | 34.26 | 0.908 | 16.34 | 83.66 | 0 | 0 | 0 |
| Tank Farm 2 | 37,974,800 | 35.5 | 0.558 | 13.74 | 86.25 | 0.01 | 0 | 0 |
| Tank Farm 3 | 71,407,306 | 25.12 | 0.864 | 43.15 | 56.83 | 0.02 | 0 | 0 |
| Tank Farm 4 | 738,682 | 19.89 | 0.378 | 70.81 | 24.75 | 4.44 | 0 | 0 |
| Tank Farm 5 | 187,980 | 31.06 | 0.918 | 23.99 | 75.81 | 0.2 | 0 | 0 |
| Tank Farm 6 | 1,302,932 | 42.75 | 1.075 | 1.94 | 95.28 | 2.78 | 0 | 0 |
| Tank Farm 7 | 453,483 | 20.5 | 0.333 | 65.94 | 33.45 | 0.61 | 0 | 0 |
| Tank Farm 8 | 32,724 | 19.69 | 1.159 | 72.04 | 21.28 | 6.67 | 0.01 | 0 |
| Tank Farm 9 | 5,279 | 22.45 | 2.085 | 56.29 | 38.35 | 5.36 | 0 | 0 |
| Tank Farm 10 | 31,928,149 | 38.26 | 1.103 | 8.42 | 90.07 | 1.51 | 0 | 0 |
| Tank Farm 11 | 71,289 | 41.95 | 0.492 | 3.02 | 96.27 | 0.71 | 0 | 0 |
| Tank Farm 12 | 3,166,001 | 40.14 | 1.197 | 5.7 | 93.67 | 0.63 | 0 | 0 |
| Tank Farm 13 | 90,549 | 38.25 | 1.532 | 8.84 | 89.14 | 2.02 | 0 | 0 |
| Tank Farm 14 | 555,341 | 44.37 | 0.103 | 10.72 | 14.56 | 74.72 | 0 | 0 |
| Tank Farm 15 | 25,821 | 21.52 | 0.898 | 60.13 | 39.14 | 0.73 | 0 | 0 |
| Tank Farm 16 | 1,288,097 | 21.68 | 0.144 | 60.07 | 30.51 | 9.42 | 0 | 0 |
| Tank Farm 17 | 6,480,307 | 37.54 | 0.991 | 12.22 | 79.49 | 8.29 | 0 | 0 |
| Tank Farm 18 | 461,705 | 44.01 | 0.315 | 0 | 99.96 | 0.04 | 0 | 0 |
| Tank Farm 19 | 1,037,544 | 25.38 | 1.139 | 42.01 | 46.72 | 11.27 | 0 | 0 |
| Tank Farm 20 | 1,215,654 | 32.91 | 1.102 | 19.48 | 80.07 | 0.45 | 0 | 0 |
| Tank Farm 21 | 22,713 | 32.3 | 1.061 | 20.81 | 79.12 | 0.07 | 0 | 0 |
| Tank Farm 22 | 78,514 | 34.99 | 2.246 | 14.83 | 85.04 | 0.13 | 0 | 0 |

## Table D-16: WSPA Crude Dataset #2

| | Crude Oil Flash Sample | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Crude Throughput (bbl)** | **Reid Vapor Pressure (psia)** | **Crude Oil API Gravity** | **Flash Gas MW (g/g-mole)** | **GOR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 1 | 1,225,438 | 3.7 | 26.3 | 31.42 | 11.824 | 24.45 | 34.71 | 30.86 | 0 | 0.01 |
| Tank Farm 10 | 788,450 | 0.2 | 10.8 | 18.67 | 3.063 | 77.05 | 19.7 | 0.12 | 0 | 0 |
| Tank Farm 101 | 1,030,740 | 0.9 | 16.8 | 18.9746 | 1.852581 | 76.81431 | 15.82913 | 6.377339 | 0 | 0 |
| Tank Farm 103 | 3,246 | 0.4 | 15.2 | 20.375 | 1.963078 | 51.49176 | 2.418754 | 0.012539 | 0 | 0 |
| Tank Farm 105 | 5,946 | 0.3 | 13.2 | 16.92876 | 331.2604 | 88.01012 | 0.501345 | 0 | 0 | 0 |
| Tank Farm 106 | 5,991 | 0.3 | 15 | 16.69867 | 1.248221 | 94.22659 | 4.32881 | 1.444604 | 0 | 0 |
| Tank Farm 107 | 10,159 | 1.1 | 16.5 | 20.83107 | 2.017638 | 59.2504 | 6.865083 | 14.57106 | 0 | 0 |
| Tank Farm 108 | 37,985 | 5.3 | 35.3 | 31.87611 | 15.63251 | 22.89939 | 0 | 60.00559 | 0.000694 | 0.023967 |
| Tank Farm 109 | 272 | 1.5 | 20.2 | 21.65979 | 15.82216 | 56.13387 | 10.81279 | 16.24968 | 0 | 0 |
| Tank Farm 11 | 334,663 | 0.6 | 10.7 | 20.67 | 0.857 | 61.1 | 20.81 | 3.61 | 0 | 0 |
| Tank Farm 110 | 45,395 | 3.7 | 20.6 | 43.21828 | 3.195757 | 5.559086 | 0.475081 | 82.67105 | 0 | 0.018662 |
| Tank Farm 111 | 392,686 | 0.65 | 15.4 | 18.42371 | 3.498334 | 76.45615 | 9.91468 | 2.639746 | 0 | 0 |
| Tank Farm 112 | 18,726 | 1 | 20.7 | 22.50258 | 9.316953 | 53.72506 | 22.46505 | 13.57988 | 0.001242 | 0 |
| Tank Farm 113 | 4,879 | 8 | 37.5 | 33.71681 | 42.09923 | 16.13935 | 0.153939 | 60.33903 | 0.000878 | 0.015472 |
| Tank Farm 114 | 73,541 | 8.6 | 34.6 | 44.75252 | 16.05923 | 5.402023 | 0.294284 | 84.41408 | 0.001111 | 0.003407 |
| Tank Farm 115 | 31,864 | 2.7 | 32.5 | 47.00499 | 7.423727 | 4.882739 | 16.74217 | 73.6173 | 0 | 0 |
| Tank Farm 116 | 98,376 | 6 | 29.1 | 40.77252 | 29.53785 | 7.571031 | 6.333711 | 69.99259 | 0 | 0 |
| Tank Farm 117 | 98,376 | 5.4 | 30.9 | 43.15119 | 63.38001 | 3.836978 | 9.468192 | 71.11549 | 0 | 0 |
| Tank Farm 118 | 197,040 | 4.2 | 33.2 | 43.5546 | 6.397833 | 7.864757 | 7.865012 | 74.75683 | 0 | 0 |
| Tank Farm 119 | 14,976 | 5.4 | 36.2 | 48.17265 | 19.06956 | 3.061039 | 0.68618 | 84.86298 | 0 | 0 |
| Tank Farm 120 | 43,215 | 4.8 | 28.6 | 44.81802 | 9.286603 | 6.589311 | 0.341968 | 84.28561 | 0 | 0 |
| Tank Farm 121 | 13,098 | 3.7 | 22 | 47.53639 | 2.786334 | 5.54786 | 0 | 88.19923 | 0 | 0.010518 |
| Tank Farm 125 | 197,040 | 3.4 | 30 | 37.54187 | 28.70456 | 11.84967 | 9.403102 | 62.70886 | 0 | 0 |
| Tank Farm 126 | 446,056 | 5.3 | 21 | 34.61139 | 4.196467 | 20.20899 | 0.872949 | 68.72063 | 0 | 0 |
| Tank Farm 127 | 69,133 | 1.8 | 21.2 | 27.22455 | 4.44204 | 40.61628 | 5.151408 | 47.18989 | 0.001434 | 0 |
| Tank Farm 13 | 159,873 | 0.2 | 10.8 | 20.94 | 0.939 | 55.16 | 15.82 | 2 | 0 | 0 |
| Tank Farm 130 | 76,499 | 3 | 17.8 | 25.24961 | 8.584963 | 42.85463 | 0.745305 | 41.95402 | 0.001641 | 0 |

| | Crude Oil Flash Sample | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Crude Throughput (bbl)** | **Reid Vapor Pressure (psia)** | **Crude Oil API Gravity** | **Flash Gas MW (g/g-mole)** | **GOR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 131 | 12,314 | 3.2 | 23.6 | 35.32927 | 6.81985 | 19.70136 | 0.194455 | 70.33054 | 0.002078 | 0.010824 |
| Tank Farm 132 | 24,861 | 0.5 | 12.6 | 31.47617 | 0.804743 | 28.43912 | 0.786779 | 63.41138 | 0 | 0 |
| Tank Farm 134 | 52,798 | 2 | 24.2 | 27.07014 | 3.267658 | 41.32338 | 6.551257 | 47.83917 | 0 | 0.042214 |
| Tank Farm 135 | 57,772 | 3.4 | 18.6 | 39.88153 | 3.934664 | 10.75618 | 0 | 78.5917 | 0 | 0 |
| Tank Farm 136 | 1,882 | 2.8 | 28.9 | 36.72705 | 3.66299 | 17.19755 | 0.406666 | 70.10884 | 0.001153 | 0.013748 |
| Tank Farm 137 | 16,607 | 2.1 | 22.7 | 25.51451 | 16.78665 | 42.82269 | 0.109983 | 45.30262 | 0.001728 | 0 |
| Tank Farm 138 | 9,348 | 1.7 | 17.9 | 54.89345 | 10.17449 | 3.330442 | 0.947596 | 90.07534 | 0 | 0 |
| Tank Farm 139 | 4,589 | 2.9 | 15.7 | 42.49846 | 2.098869 | 13.20214 | 0.655421 | 80.53433 | 0.002609 | 0.016291 |
| Tank Farm 14 | 159,873 | 0.5 | 11 | 25.73 | 0.444 | 17.29 | 7.74 | 1.74 | 0 | 0 |
| Tank Farm 140 | 475 | 3.1 | 15.5 | 33.85558 | 5.781136 | 23.8388 | 0 | 67.12369 | 0.003277 | 0.015173 |
| Tank Farm 141 | 11,905 | 1.3 | 15 | 24.69047 | 10.78745 | 44.77728 | 0.647883 | 39.60552 | 0.002199 | 0 |
| Tank Farm 142 | 8,470 | 3.4 | 30.3 | 50.56633 | 2.235243 | 4.313184 | 0 | 94.34553 | 0.002117 | 0.017767 |
| Tank Farm 143 | 230,900 | 5.1 | 31.2 | 34.17152 | 14.47074 | 19.20723 | 0.246908 | 65.23372 | 0 | 0.00746 |
| Tank Farm 144 | 3,860 | 4.8 | 23.6 | 28.9988 | 8.452952 | 31.28668 | 0 | 54.25642 | 0 | 0 |
| Tank Farm 145 | 6,263 | 6.3 | 30.7 | 53.92558 | 7.213503 | 1.087803 | 0 | 95.9566 | 0 | 0.013018 |
| Tank Farm 146 | 9,949 | 2.2 | 15.2 | 34.27251 | 4.731513 | 23.17662 | 0.736501 | 67.60692 | 0 | 0.009688 |
| Tank Farm 147 | 23,190 | 3.3 | 21 | 34.3989 | 6.587397 | 20.81514 | 0.178336 | 67.29355 | 0.003185 | 0.007273 |
| Tank Farm 148 | 100,103 | 1 | 32.8 | 28.16765 | 10.76782 | 21.54303 | 0.694377 | 30.10744 | 0.0018 | 0.005534 |
| Tank Farm 149 | 451,954 | 1.8 | 17.4 | 40.87175 | 3.521652 | 9.946971 | 0.13783 | 79.06972 | 0.002869 | 0 |
| Tank Farm 150 | 182,231 | 2.5 | 18 | 34.57243 | 7.278493 | 8.617933 | 0.118263 | 53.49722 | 0.001522 | 0 |
| Tank Farm 151 | 54,529 | 6.9 | 31.6 | 36.84871 | 28.45833 | 11.84825 | 0.65292 | 68.2489 | 0.000235 | 0.003256 |
| Tank Farm 152 | 8,961 | 2 | 18.7 | 32.54065 | 17.51002 | 19.90595 | 0.377781 | 58.15504 | 0.001468 | 0.007657 |
| Tank Farm 153 | 982,205 | 5.2 | 24.7 | 36.37839 | 7.445378 | 20.01664 | 2.206124 | 72.32742 | 0.00182 | 0 |
| Tank Farm 154 | 14,714 | 6 | 30.5 | 47.82508 | 6.887994 | 2.097897 | 0.568047 | 85.8691 | 0.001655 | 0.008108 |
| Tank Farm 155 | 982,205 | 5.1 | 27.8 | 47.67457 | 9.736298 | 5.861646 | 1.864361 | 88.12752 | 0.001196 | 0.00487 |
| Tank Farm 156 | 23,067 | 6.5 | 28.7 | 37.79354 | 21.26961 | 10.68362 | 0.352376 | 68.91121 | 0.000936 | 0.009062 |
| Tank Farm 157 | 1,428 | 4.9 | 30.6 | 45.51571 | 5.910931 | 3.062297 | 0.234706 | 79.70632 | 0.000683 | 0.011953 |
| Tank Farm 158 | 95,039 | 5 | 25.1 | 40.42334 | 6.725365 | 12.73658 | 0 | 77.93926 | 0.003481 | 0.011585 |
| Tank Farm 159 | 759 | 2.4 | 25.4 | 28.89214 | 5.431524 | 32.60933 | 0.634649 | 50.76462 | 0.00073 | 0.022027 |

| | Crude Oil Flash Sample | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Crude Throughput (bbl)** | **Reid Vapor Pressure (psia)** | **Crude Oil API Gravity** | **Flash Gas MW (g/g-mole)** | **GOR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 16 | 913 | 0.4 | 0 | 58.5 | 5.336 | 35.08 | 61.46 | 3.08 | 0 | 0 |
| Tank Farm 160 | 10,320 | 6.1 | 28.7 | 34.01147 | 33.33109 | 17.24264 | 0.515361 | 63.07859 | 0.001161 | 0.005085 |
| Tank Farm 162 | 27,901 | 1.4 | 8.5 | 38.41514 | 17.35586 | 14.61501 | 1.139264 | 72.59916 | 0.002874 | 0.008168 |
| Tank Farm 163 | 2,671 | 4.6 | 31.7 | 51.73715 | 2.661966 | 2.369865 | 2.063434 | 88.23341 | 0.004175 | 0.01113 |
| Tank Farm 165 | 29,112 | 4.6 | 31.9 | 38.08682 | 14.62469 | 14.47845 | 1.944299 | 73.59896 | 0.001034 | 0.006334 |
| Tank Farm 17 | 68,547 | 0.8 | 10.3 | 33.7 | 0.363 | 18.91 | 76.22 | 4.87 | 0 | 0 |
| Tank Farm 19 | 292,532 | 0.6 | 10.8 | 18.83 | 3.156 | 75.48 | 19.04 | 0.36 | 0 | 0 |
| Tank Farm 2 | 1,673,425 | 0.9 | 12.3 | 27.62 | 2.473 | 34 | 63.98 | 1.4 | 0 | 0 |
| Tank Farm 20 | 93,379 | 2.2 | 23.3 | 31.87 | 3.346 | 25.01 | 33.42 | 35.45 | 0 | 0 |
| Tank Farm 21 | 409,977 | 0.9 | 12.7 | 24.64 | 1.333 | 45.43 | 51.26 | 2.33 | 0 | 0 |
| Tank Farm 22 | 2,618,564 | 0.4 | 13.2 | 29.13 | 0.901 | 29.3 | 68.51 | 1.02 | 0 | 0 |
| Tank Farm 23 | 423,266 | 0.5 | 13.4 | 29.84 | 4.343 | 27.2 | 72.49 | 0.02 | 0 | 0 |
| Tank Farm 24 | 1,072,965 | 0.5 | 11 | 32.21 | 0.680 | 20.83 | 77.01 | 0.37 | 0 | 0 |
| Tank Farm 25 | 255,542 | 0.3 | 12.9 | 30.25 | 0.793 | 24.36 | 64.7 | 2.86 | 0 | 0 |
| Tank Farm 26 | 1,113,128 | 0.6 | 11 | 33.17 | 0.932 | 18.43 | 79.55 | 0.07 | 0 | 0 |
| Tank Farm 27 | 1,113,128 | 0.4 | 12.8 | 24.19 | 2.127 | 46.37 | 49.2 | 0.75 | 0 | 0 |
| Tank Farm 28 | 179,848 | 1.8 | 22 | 32.17 | 10.815 | 18.18 | 51.92 | 13.91 | 0 | 0 |
| Tank Farm 3 | 992,565 | 1 | 13.8 | 24.94 | 8.956 | 43.68 | 54.16 | 1.02 | 0 | 0 |
| Tank Farm 30 | 179,848 | 0.5 | 14.2 | 27.95 | 7.488 | 12 | 16.41 | 2.13 | 0 | 0 |
| Tank Farm 32 | 834,956 | 0.5 | 0 | 59.8 | 3.882 | 57.51 | 34.71 | 0.32 | 0 | 0 |
| Tank Farm 33 | 459,922 | 0.4 | 18.3 | 25.6 | 2.362 | 40.46 | 56.44 | 0.05 | 0 | 0 |
| Tank Farm 34 | 179,848 | 6.9 | 31.4 | 34.69 | 45.095 | 16.43 | 16.51 | 52.66 | 0 | 0 |
| Tank Farm 35 | 1,113,128 | 1 | 18.7 | 29.75 | 2.438 | 16.04 | 31.53 | 8.48 | 0 | 0 |
| Tank Farm 36 | 179,848 | 1.6 | 21.9 | 28.32 | 8.438 | 31.83 | 41.29 | 18.87 | 0 | 0 |
| Tank Farm 37 | 179,848 | 2.6 | 21.8 | 37.28 | 6.121 | 11.6 | 65.62 | 18.63 | 0 | 0 |
| Tank Farm 39 | 1,325,555 | 7.8 | 30.7 | 44.06 | 16.548 | 5.85 | 1.12 | 84.13 | 0 | 0 |
| Tank Farm 4 | 15,271,669 | 4.8 | 28.1 | 40.15 | 9.153 | 11.23 | 23.79 | 59.5 | 0 | 0 |
| Tank Farm 40 | 294,540 | 6.2 | 30.3 | 42.46 | 12.372 | 10.55 | 3.07 | 81.77 | 0 | 0.01 |
| Tank Farm 41 | 1,086,818 | 7.1 | 29.1 | 45.86 | 10.909 | 6.13 | 0.8 | 87 | 0 | 0.01 |

| | Crude Oil Flash Sample | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Crude Throughput (bbl)** | **Reid Vapor Pressure (psia)** | **Crude Oil API Gravity** | **Flash Gas MW (g/g-mole)** | **GOR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 42 | 1,958,644 | 4.9 | 28.8 | 49.06 | 5.080 | 4.88 | 2.33 | 89.55 | 0 | 0.02 |
| Tank Farm 43 | 424,603 | 8.3 | 32.5 | 47.38 | 10.329 | 5.59 | 1.57 | 88.67 | 0 | 0 |
| Tank Farm 44 | 33,174 | 2.6 | 26.5 | 32.46143 | 8.884517 | 26.68646 | 7.383677 | 59.91604 | 0.000505 | 0.015503 |
| Tank Farm 45 | 176,209 | 2.7 | 28.2 | 34.38947 | 11.13063 | 18.79762 | 6.521442 | 62.17677 | 0 | 0 |
| Tank Farm 46 | 51,684 | 7.5 | 33.1 | 43.84607 | 29.31854 | 5.271561 | 2.329941 | 81.5765 | 0 | 0.037017 |
| Tank Farm 47 | 38,493 | 5.6 | 25.7 | 38.44332 | 6.950425 | 14.77541 | 2.139958 | 77.11208 | 0 | 0 |
| Tank Farm 48 | 14,743 | 2.9 | 33.2 | 35.68696 | 10.80139 | 17.77345 | 0.25453 | 68.28692 | 0.000756 | 0.015066 |
| Tank Farm 5 | 8,736,302 | 0.6 | 20.2 | 27.96 | 1.151 | 35.4 | 41.77 | 21.3 | 0 | 0 |
| Tank Farm 50 | 647,573 | 3 | 25.2 | 25.27817 | 50.71236 | 25.18014 | 2.363251 | 14.03833 | 0 | 0 |
| Tank Farm 51 | 58,472 | 3.4 | 31.2 | 29.15229 | 10.73545 | 31.69697 | 5.735076 | 50.23638 | 0 | 0.07446 |
| Tank Farm 53 | 147,004 | 3 | 27.5 | 31.75527 | 23.91285 | 26.65227 | 8.000574 | 57.08218 | 0.001041 | 0.007399 |
| Tank Farm 54 | 171,474 | 2.4 | 27.2 | 40.42545 | 5.108398 | 4.577803 | 1.30779 | 62.68888 | 0.001905 | 0 |
| Tank Farm 55 | 91,607 | 2.3 | 27.4 | 39.65949 | 5.830681 | 4.501521 | 13.46039 | 52.50332 | 0.001623 | 0 |
| Tank Farm 56 | 647,573 | 2.4 | 25.5 | 32.58563 | 11.70836 | 25.73761 | 7.49886 | 61.1296 | 0.002978 | 0.006781 |
| Tank Farm 57 | 23,425 | 2.5 | 29.6 | 31.1323 | 6.832823 | 22.31762 | 3.78888 | 48.50452 | 0.002153 | 0.011705 |
| Tank Farm 58 | 28,827 | 2.7 | 25.5 | 47.06796 | 0.905879 | 8.815327 | 0.75708 | 88.94609 | 0 | 0.003189 |
| Tank Farm 6 | 8,736,302 | 0.6 | 12.7 | 26.88 | 4.878 | 36.6 | 61.97 | 1.1 | 0 | 0 |
| Tank Farm 60 | 91,607 | 1.7 | 24.9 | 24.70545 | 21.78475 | 48.09194 | 5.544902 | 39.00801 | 0.001067 | 0.004706 |
| Tank Farm 62 | 6,685 | 1.3 | 16.3 | 38.22025 | 8.835261 | 7.799713 | 87.36699 | 1.300817 | 0 | 0 |
| Tank Farm 63 | 7,835 | 2.4 | 24.8 | 31.91621 | 10.89066 | 18.02924 | 25.32187 | 30.29639 | 0.003446 | 0 |
| Tank Farm 64 | 2,429,842 | 0.05 | 11.8 | 25.02802 | 1.930764 | 42.87924 | 53.92315 | 0.417246 | 0 | 0 |
| Tank Farm 65 | 6,198 | 0.6 | 21.8 | 22.70541 | 2.280086 | 44.12612 | 2.776589 | 14.72547 | 0 | 0 |
| Tank Farm 66 | 292,695 | 0.65 | 13.1 | 28.53116 | 2.230643 | 31.27206 | 63.25923 | 4.067557 | 0 | 0 |
| Tank Farm 67 | 54,139 | 2.6 | 26.1 | 26.28301 | 16.4475 | 39.23859 | 16.46356 | 33.09485 | 0 | 0 |
| Tank Farm 68 | 7,091 | 1.7 | 25.6 | 24.63603 | 14.39281 | 47.19412 | 34.545 | 16.70307 | 0.000746 | 0 |
| Tank Farm 71 | 8,747 | 1.8 | 20.8 | 43.77519 | 0.852807 | 11.55967 | 26.10169 | 61.41782 | 0 | 0 |
| Tank Farm 72 | 2,517 | 2.3 | 21.9 | 26.26467 | 12.09783 | 35.60027 | 36.04818 | 12.73909 | 0.003762 | 0 |
| Tank Farm 73 | 2,285 | 0.5 | 10.7 | 25.06415 | 5.074412 | 43.38871 | 56.22962 | 0.236134 | 0 | 0 |
| Tank Farm 76 | 659,826 | 6.1 | 30.9 | 40.31714 | 17.92482 | 10.99271 | 2.244656 | 77.28431 | 0 | 0.003924 |

| Tank Farm | Crude Oil Flash Sample | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 Crude Throughput (bbl) | Reid Vapor Pressure (psia) | Crude Oil API Gravity | Flash Gas MW (g/g-mole) | GOR (scf/bbl) | Methane (Wt%) | CO2 (Wt%) | VOC [C3-C10] (Wt%) | VOC [C10+] (Wt%) | BTEX (Wt%) |
| Tank Farm 79 | 48,779 | 1.6 | 20.4 | 25.44395 | 6.37031 | 32.39621 | 9.509104 | 19.10728 | 0.004657 | 0 |
| Tank Farm 80 | 8,393 | 2.4 | 20.4 | 42.03111 | 3.142197 | 6.298519 | 26.40593 | 52.32153 | 0.00281 | 0 |
| Tank Farm 85 | 4,440,933 | 0.5 | 12.5 | 16.43225 | 8.980984 | 95.23163 | 1.51618 | 0.013027 | 0 | 0 |
| Tank Farm 87 | 57,995 | 0.3 | 14.2 | 17.89701 | 14.56877 | 80.11172 | 8.352089 | 0.365906 | 0 | 0 |
| Tank Farm 89 | 4,440,933 | 0.4 | 14.6 | 22.7532 | 6.417227 | 45.12859 | 27.47294 | 0.963332 | 0 | 0 |
| Tank Farm 9 | 992,565 | 0.5 | 12.4 | 21.89 | 0.359 | 57.71 | 39.53 | 0.4 | 0 | 0 |
| Tank Farm 90 | 57,995 | 0.3 | 13.3 | 16.90629 | 9.275279 | 91.10967 | 6.267619 | 0.006696 | 0 | 0 |
| Tank Farm 91 | 924,983 | 6.5 | 25.8 | 38.64536 | 8.516479 | 14.66144 | 0.30188 | 76.75049 | 0.001192 | 0.003904 |
| Tank Farm 92 | 53,550 | 2.9 | 32.4 | 29.66795 | 17.43035 | 27.80564 | 15.49417 | 42.10791 | 0.00145 | 0.009113 |
| Tank Farm 93 | 112,836 | 4.7 | 28.5 | 35.12511 | 21.27871 | 18.26431 | 12.34313 | 60.16095 | 0.00106 | 0.004967 |
| Tank Farm 94 | 862,980 | 2.6 | 25.8 | 26.42987 | 14.82285 | 43.00515 | 1.936053 | 50.19446 | 0.000586 | 0.00338 |
| Tank Farm 95 | 606,518 | 1.5 | 20.5 | 23.56843 | 8.910803 | 53.73177 | 1.967473 | 39.34993 | 0.001636 | 0 |
| Tank Farm 96 | 10,531 | 0.6 | 20.2 | 17.30857 | 2.725726 | 87.58494 | 3.827073 | 3.591284 | 0 | 0 |
| Tank Farm 97 | 57,643 | 0.4 | 16.4 | 33.14946 | 1.947594 | 20.54071 | 58.92049 | 17.89037 | 0 | 0 |
| Tank Farm 98 | 6,972 | 0.4 | 14.8 | 18.77994 | 8.051823 | 66.79634 | 1.217255 | 0.352792 | 0 | 0 |

**Table D-17: WSPA Water Dataset #2**

| | Produced Water Flash Sample | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Water Throughput (bbl)** | **Flash Gas MW (g/g-mole)** | **GWR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 85 | 69,961,303 | 16.98157486 | 0.686204 | 91.31088 | 8.659109 | 0.030008 | 0 | 0 |
| Tank Farm 6 | 152,582,286 | 39.42 | 1.767 | 6.69 | 93.26 | 0.06 | 0 | 0 |
| Tank Farm 89 | 69,961,303 | 32.01473925 | 1.257251 | 21.50131 | 78.46952 | 0.029173 | 0 | 0 |
| Tank Farm 4 | 157,320,153 | 40.54 | 1.463 | 5.67 | 90.41 | 3.92 | 0 | 0 |
| Tank Farm 74 | 31,848,216 | 25.04936978 | 1.329654 | 44.62852 | 42.84264 | 10.89398 | 0 | 0 |
| Tank Farm 5 | 152,582,286 | 38.63 | 0.835 | 7.98 | 91.94 | 0.01 | 0 | 0 |
| Tank Farm 111 | 20,816,607 | 20.85572489 | 0.801158 | 63.68624 | 36.31376 | 0 | 0 | 0 |
| Tank Farm 64 | 31,928,149 | 38.25516636 | 1.103001 | 8.416178 | 90.06941 | 0.089023 | 0 | 0 |
| Tank Farm 84 | 11,845,861 | 19.39184939 | 0.677077 | 72.83505 | 27.1264 | 0.038552 | 0 | 0 |
| Tank Farm 83 | 11,845,861 | 23.46767835 | 0.707565 | 48.16194 | 45.50862 | 0.036044 | 0 | 0 |
| Tank Farm 22 | 34,502,591 | 40.36 | 1.257 | 5.14 | 94.58 | 0.01 | 0 | 0 |
| Tank Farm 9 | 19,388,356 | 35.64 | 1.180 | 10.79 | 73.11 | 0.03 | 0 | 0 |
| Tank Farm 49 | 31,848,216 | 41.13003981 | 1.575893 | 4.206514 | 95.11716 | 0.676327 | 0 | 0 |
| Tank Farm 3 | 19,388,356 | 38.52 | 1.364 | 8.18 | 91.71 | 0.06 | 0 | 0 |
| Tank Farm 75 | 31,848,216 | 24.94959978 | 0.236006 | 44.34209 | 49.20346 | 5.345632 | 0 | 0 |
| Tank Farm 82 | 11,845,861 | 18.29448491 | 0.396476 | 80.64331 | 19.32123 | 0.035457 | 0 | 0 |
| Tank Farm 1 | 12,342,046 | 38.98 | 1.667 | 7.86 | 88.42 | 3.09 | 0 | 0 |
| Tank Farm 42 | 17,788,511 | 36.88 | 0.584 | 11.12 | 88.76 | 0.12 | 0 | 0 |
| Tank Farm 87 | 2,348,729 | 18.44444684 | 1.178439 | 79.51303 | 20.4807 | 0.006037 | 0 | 0 |
| Tank Farm 10 | 6,967,019 | 34.97 | 1.289 | 11.93 | 70.53 | 0.08 | 0 | 0 |
| Tank Farm 88 | 10,132,193 | 30.61144732 | 0.471378 | 25.12859 | 74.79841 | 0.073009 | 0 | 0 |
| Tank Farm 2 | 19,388,356 | 41.1 | 1.102 | 4.07 | 95.89 | 0.04 | 0 | 0 |
| Tank Farm 40 | 6,149,164 | 33.43 | 0.875 | 18.16 | 81.79 | 0.04 | 0 | 0 |
| Tank Farm 39 | 7,780,946 | 29.5 | 0.483 | 28.25 | 71.59 | 0.16 | 0 | 0 |
| Tank Farm 27 | 14,790,748 | 39.54 | 1.516 | 3.42 | 78.18 | 0.02 | 0 | 0 |
| Tank Farm 99 | 2,925,394 | 21.80299036 | 0.802083 | 58.42702 | 41.57298 | 0 | 0 | 0 |
| Tank Farm 45 | 6,480,307 | 37.53807818 | 0.990809 | 12.21836 | 79.48539 | 8.29538 | 0 | 0 |

| | Produced Water Flash Sample | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Water Throughput (bbl)** | **Flash Gas MW (g/g-mole)** | **GWR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 90 | 2,348,729 | 22.7567476 | 1.003005 | 53.57676 | 46.41376 | 0.009474 | 0 | 0 |
| Tank Farm 77 | 6,254,997 | 36.14396473 | 0.821809 | 14.82453 | 72.43285 | 12.74262 | 0 | 0 |
| Tank Farm 34 | 2,864,213 | 33.7 | 1.476 | 17.17 | 80.73 | 0.62 | 0 | 0 |
| Tank Farm 105 | 1,226,854 | 17.54395056 | 0.98 | 86.53692 | 13.46308 | 0 | 0 | 0 |
| Tank Farm 11 | 2,404,306 | 33.34 | 1.377 | 16.51 | 72.36 | 0.02 | 0 | 0 |
| Tank Farm 94 | 2,860,805 | 24.55832735 | 0.534508 | 45.73167 | 53.21412 | 1.054212 | 0 | 0 |
| Tank Farm 35 | 14,790,748 | 37.97 | 0.557 | 5.47 | 72.3 | 0.12 | 0 | 0 |
| Tank Farm 19 | 2,897,597 | 31.1 | 0.877 | 20.65 | 60.41 | 0.02 | 0 | 0 |
| Tank Farm 78 | 2,493,018 | 27.3543444 | 0.577617 | 38.02141 | 36.10269 | 22.43199 | 0.012047 | 0 |
| Tank Farm 41 | 3,072,889 | 31.35 | 0.666 | 21.65 | 72.49 | 0.06 | 0 | 0 |
| Tank Farm 58 | 1,739,541 | 24.59952693 | 0.607521 | 52.47416 | 9.633247 | 37.8926 | 0 | 0 |
| Tank Farm 67 | 1,037,544 | 25.38232449 | 1.139159 | 42.00506 | 46.72132 | 7.657799 | 0.001028 | 0 |
| Tank Farm 101 | 1,349,022 | 21.66679956 | 0.709101 | 60.57593 | 33.07231 | 6.351753 | 0 | 0 |
| Tank Farm 32 | 6,264,112 | 35.97 | 0.451 | 9.8 | 72.59 | 0.06 | 0 | 0 |
| Tank Farm 12 | 4,468,777 | 38.95 | 0.948 | 5.3 | 81.82 | 0.01 | 0 | 0 |
| Tank Farm 24 | 4,875,954 | 41.46 | 1.227 | 3.51 | 96.4 | 0 | 0 | 0 |
| Tank Farm 66 | 3,166,001 | 40.14426221 | 1.197072 | 5.6964 | 93.66531 | 0.623342 | 0 | 0 |
| Tank Farm 44 | 1,215,654 | 32.90847632 | 1.101967 | 19.4782 | 80.07037 | 0.451424 | 0 | 0 |
| Tank Farm 50 | 985,630 | 28.41391197 | 0.947147 | 32.33292 | 64.65152 | 3.015556 | 0 | 0 |
| Tank Farm 92 | 2,865,262 | 38.23787887 | 0.844347 | 8.659271 | 91.34073 | 0 | 0 | 0 |
| Tank Farm 28 | 2,864,213 | 40.99 | 1.934 | 3.47 | 91.96 | 0.01 | 0 | 0 |
| Tank Farm 43 | 4,914,999 | 30.64 | 0.181 | 28.86 | 48.74 | 22.4 | 0 | 0 |
| Tank Farm 95 | 1,299,398 | 32.83559835 | 0.939167 | 19.52176 | 80.47824 | 0 | 0 | 0 |
| Tank Farm 30 | 2,864,213 | 37.89 | 1.256 | 4.96 | 69.19 | 0.06 | 0 | 0 |
| Tank Farm 23 | 2,482,846 | 41.38 | 1.694 | 3.64 | 96.36 | 0 | 0 | 0 |
| Tank Farm 26 | 14,790,748 | 42.41 | 0.595 | 1.61 | 95.09 | 0.01 | 0 | 0 |
| Tank Farm 36 | 2,864,213 | 40.38 | 1.055 | 4.8 | 93.71 | 0.2 | 0 | 0 |
| Tank Farm 33 | 4,070,860 | 40.31 | 0.648 | 4.5 | 90.87 | 0.03 | 0 | 0 |
| Tank Farm 102 | 2,192,751 | 29.67582237 | 0.264687 | 27.6879 | 72.19009 | 0 | 0 | 0 |

| | Produced Water Flash Sample | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Tank Farm** | **2014 Water Throughput (bbl)** | **Flash Gas MW (g/g-mole)** | **GWR (scf/bbl)** | **Methane (Wt%)** | **CO2 (Wt%)** | **VOC [C3-C10] (Wt%)** | **VOC [C10+] (Wt%)** | **BTEX (Wt%)** |
| Tank Farm 21 | 2,177,225 | 39.04 | 0.775 | 7.2 | 92.14 | 0.01 | 0 | 0 |
| Tank Farm 56 | 985,630 | 30.84225055 | 0.524832 | 26.2085 | 66.46658 | 7.322867 | 0 | 0 |
| Tank Farm 20 | 2,177,225 | 41.42 | 1.394 | 3.21 | 95.61 | 0.01 | 0 | 0 |
| Tank Farm 143 | 738,682 | 19.89057249 | 0.378419 | 70.80717 | 24.74945 | 4.443373 | 0 | 0 |
| Tank Farm 93 | 731,049 | 35.59965714 | 1.006542 | 13.23172 | 85.55293 | 0.005105 | 0 | 0 |
| Tank Farm 37 | 2,864,213 | 42.81 | 1.623 | 1.62 | 98.34 | 0.05 | 0 | 0 |
| Tank Farm 13 | 738,060 | 34.81 | 0.861 | 11.92 | 68.68 | 0.01 | 0 | 0 |
| Tank Farm 91 | 1,288,097 | 21.68489871 | 0.144493 | 60.0738 | 30.51059 | 9.415611 | 0 | 0 |
| Tank Farm 148 | 453,483 | 20.50330939 | 0.332865 | 65.93777 | 33.45341 | 0.608822 | 0 | 0 |
| Tank Farm 127 | 187,980 | 31.05642746 | 0.918385 | 23.98527 | 75.80509 | 0.209641 | 0 | 0 |
| Tank Farm 118 | 1,302,932 | 42.74989214 | 1.075133 | 1.936619 | 95.27612 | 2.787264 | 0 | 0 |
| Tank Farm 108 | 476,869 | 16.043 | 0.145414 | 100 | 0 | 0 | 0 | 0 |
| Tank Farm 25 | 1,514,226 | 40.98 | 0.400 | 4.1 | 94.53 | 0.19 | 0 | 0 |
| Tank Farm 72 | 78,514 | 34.98694974 | 2.245833 | 14.8283 | 85.04026 | 0.125545 | 0 | 0 |
| Tank Farm 7 | 312,763 | 36.64 | 0.758 | 8.5 | 73.34 | 0 | 0 | 0 |
| Tank Farm 46 | 112,125 | 30.78881663 | 0.721875 | 24.80844 | 74.56647 | 0.625092 | 0 | 0 |
| Tank Farm 96 | 73,059 | 25.08634462 | 0.772005 | 43.27204 | 56.72796 | 0 | 0 | 0 |
| Tank Farm 79 | 32,724 | 19.69365075 | 1.15901 | 72.04285 | 21.27834 | 6.213724 | 0.010202 | 0 |
| Tank Farm 126 | 1,545,601 | 26.47860516 | 0.032083 | 38.01458 | 61.85011 | 0.126521 | 0 | 0 |
| Tank Farm 63 | 90,549 | 38.24817329 | 1.532428 | 8.836821 | 89.13807 | 1.399906 | 0.000569 | 0 |
| Tank Farm 48 | 25,821 | 21.52429507 | 0.898333 | 60.13132 | 39.13817 | 0.730511 | 0 | 0 |
| Tank Farm 114 | 555,341 | 44.37179686 | 0.102831 | 10.72089 | 14.55749 | 71.99699 | 0 | 0 |
| Tank Farm 73 | 32,724 | 30.89766611 | 1.01644 | 24.37197 | 75.52878 | 0.099245 | 0 | 0 |
| Tank Farm 80 | 131,537 | 41.8160412 | 1.511997 | 2.928877 | 96.34488 | 0.205432 | 0 | 0 |
| Tank Farm 8 | 312,763 | 39.33 | 0.713 | 2.16 | 69.89 | 0 | 0 | 0 |
| Tank Farm 97 | 22,713 | 32.30093481 | 1.061266 | 20.81255 | 79.12286 | 0.06459 | 0 | 0 |
| Tank Farm 57 | 23,147 | 27.40747556 | 0.551862 | 41.6622 | 8.760026 | 46.7443 | 0 | 0 |
| Tank Farm 65 | 5,279 | 22.44764599 | 2.084542 | 56.28968 | 38.34714 | 5.36251 | 0 | 0 |
| Tank Farm 112 | 271,479 | 42.01404642 | 0.371553 | 2.793593 | 96.96268 | 0.243727 | 0 | 0 |

| | Produced Water Flash Sample | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Tank Farm | 2014 Water Throughput (bbl) | Flash Gas MW (g/g-mole) | GWR (scf/bbl) | Methane (Wt%) | CO2 (Wt%) | VOC [C3-C10] (Wt%) | VOC [C10+] (Wt%) | BTEX (Wt%) |
| Tank Farm 113 | 9,529 | 28.80673627 | 1.010625 | 30.05172 | 4.700344 | 42.36684 | 0 | 0.210823 |
| Tank Farm 71 | 71,288 | 41.94761306 | 0.492387 | 3.019242 | 96.27216 | 0.7086 | 0 | 0 |
| Tank Farm 69 | 600 | 21.3 | 4.933518 | 44.96896 | 21.29782 | 18.11352 | 0.001878 | 0 |
| Tank Farm 70 | 2,098 | 35.2232386 | 0.224999 | 16.50731 | 75.67057 | 7.822126 | 0 | 0 |
| Tank Farm 16 | 435 | 39.43 | 1.382 | 6.68 | 93.26 | 0.06 | 0 | 0 |
| Tank Farm 146 | 75 | 32.22672557 | 0.537795 | 24.22539 | 64.1923 | 11.58231 | 0 | 0 |
| Tank Farm 136 | 68 | 33.40430755 | 0.28386 | 21.85926 | 41.16462 | 25.90804 | 0 | 0 |

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# Exhibit 3

# ATTACHMENT C

# CONDENSATE TANK OIL AND GAS ACTIVITIES

# CONDENSATE TANK OIL AND GAS ACTIVITIES

This attachment provides the detailed documentation of the methods used to develop refined emission factors for volatile organic compounds emissions from condensate storage tanks.

Eastern Research Group, Inc.

# CONDENSATE TANK OIL AND GAS ACTIVITIES

FINAL REPORT

Prepared for:

Texas Commission on Environmental Quality

Air Quality Division

Prepared by:

Eastern Research Group, Inc.

October 10, 2012

ERG N0. 0292.01.011.001

# Condensate Tank Oil and Gas Activities

FINAL REPORT

Prepared for:

Miles Whitten
Texas Commission on Environmental Quality
P. O. Box 13087
Austin, TX 78711-3087

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October 10, 2012

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## List of Tables

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## List of Figures

## List of Acronyms

| Acronym | Definition |
| --- | --- |
| API | American Petroleum Institute |
| BBL | Barrel |
| BPA | Beaumont-Port Arthur |
| BTEX | Benzene, Toluene, Ethylbenzene, Xylene |
| CENRAP | Central Regional Air Planning Association |
| $CO_2$ | Carbon Dioxide |
| EPA | U.S. Environmental Protection Agency |
| ERG | Eastern Research Group |
| GOR | Gas/Oil Ratio |
| HAP | Hazardous Air Pollutants |
| HARC | Houston Advanced Research Center |
| HGB | Houston-Galveston-Brazoria |
| IPAMS | Independent Petroleum Association of Mountain States |
| lbs | Pounds |
| NSPS | New Source Performance Standard |
| psig | pounds per square inch gauge |
| QA | Quality Assurance |
| RRC | Texas Railroad Commission |
| TCEQ | Texas Commission on Environmental Quality |
| TERC | Texas Environmental Research Consortium |
| VOC | Volatile Organic Compound |
| VRU | Vapor Recovery Unit |
| WRAP | Western Regional Air Partnership |

# Executive Summary

This report is a deliverable for Texas Commission on Environmental Quality (TCEQ) Work Order No. 582-11-99776-FY12-11 to improve area source emission estimates for the oil and gas sector. Improvements will be gained through this effort by the development of refined emission factors for volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions from condensate storage tanks, as well as improved gas speciation profiles for different gas formations on a county-by-county basis.

Under this project, a review of available literature was conducted for data on emissions testing and emissions estimates for condensate tanks in Texas. In addition, data collected in the Barnett Shale Area Special Inventory conducted by TCEQ was evaluated, a phone survey of Texas condensate producers was conducted, and additional data on emissions estimates was obtained from several recent studies evaluating condensate storage tank emissions. ERG evaluated this data for its relevance and quality, and derived region-specific emission factors for eight geographic regions in the state. These emission factors are presented in Table E-1 below.

**Table E-1. County-Level VOC Emission Factors**

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Anderson | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Andrews | Permian | 7.07 | 5.90 |
| Angelina | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Aransas | Western Gulf | 11.0 | 14.8 |
| Archer | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Armstrong | Palo Duro | 7.61 | 9.75 |
| Atascosa | Eagle Ford Shale | 10.5 | 10.0 |
| Austin | Western Gulf | 11.0 | 14.8 |
| Bailey | Palo Duro | 7.61 | 9.75 |
| Bandera | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Bastrop | Western Gulf | 11.0 | 14.8 |
| Baylor | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Bee | Eagle Ford Shale | 10.5 | 10.0 |
| Bell | Western Gulf | 11.0 | 14.8 |
| Bexar | Western Gulf | 11.0 | 14.8 |
| Blanco | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Borden | Permian | 7.07 | 5.90 |
| Bosque | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Bowie | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Brazoria | Western Gulf | 11.0 | 14.8 |
| Brazos | Eagle Ford Shale | 10.5 | 10.0 |
| Brewster | Marathon Thrust Belt | 7.61 | 9.75 |

## Table E-1. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Briscoe | Palo Duro | 7.61 | 9.75 |
| Brooks | Western Gulf | 11.0 | 14.8 |
| Brown | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Burleson | Eagle Ford Shale | 10.5 | 10.0 |
| Burnet | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Caldwell | Western Gulf | 11.0 | 14.8 |
| Calhoun | Western Gulf | 11.0 | 14.8 |
| Callahan | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cameron | Western Gulf | 11.0 | 14.8 |
| Camp | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Carson | Anadarko | 3.15 | 5.87 |
| Cass | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Castro | Palo Duro | 7.61 | 9.75 |
| Chambers | Western Gulf | 11.0 | 14.8 |
| Cherokee | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Childress | Palo Duro | 7.61 | 9.75 |
| Clay | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cochran | Permian | 7.07 | 5.90 |
| Coke | Permian | 7.07 | 5.90 |
| Coleman | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Collin | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Collingsworth | Palo Duro | 7.61 | 9.75 |
| Colorado | Western Gulf | 11.0 | 14.8 |
| Comal | Western Gulf | 11.0 | 14.8 |
| Comanche | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Concho | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cooke | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Coryell | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cottle | Palo Duro | 7.61 | 9.75 |
| Crane | Permian | 7.07 | 5.90 |
| Crockett | Permian | 7.07 | 5.90 |
| Crosby | Permian | 7.07 | 5.90 |
| Culberson | Permian | 7.07 | 5.90 |
| Dallam | Palo Duro | 7.61 | 9.75 |
| Dallas | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Dawson | Permian | 7.07 | 5.90 |
| Deaf Smith | Palo Duro | 7.61 | 9.75 |
| Delta | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Denton | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| DeWitt | Eagle Ford Shale | 10.5 | 10.0 |
| Dickens | Permian | 7.07 | 5.90 |
| Dimmit | Eagle Ford Shale | 10.5 | 10.0 |
| Donley | Palo Duro | 7.61 | 9.75 |
| Duval | Western Gulf | 11.0 | 14.8 |

## Table E-1. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Eastland | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Ector | Permian | 7.07 | 5.90 |
| Edwards | Permian | 7.07 | 5.90 |
| El Paso | Permian | 7.07 | 5.90 |
| Ellis | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Erath | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Falls | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Fannin | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Fayette | Eagle Ford Shale | 10.5 | 10.0 |
| Fisher | Permian | 7.07 | 5.90 |
| Floyd | Palo Duro | 7.61 | 9.75 |
| Foard | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Fort Bend | Western Gulf | 11.0 | 14.8 |
| Franklin | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Freestone | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Frio | Eagle Ford Shale | 10.5 | 10.0 |
| Gaines | Permian | 7.07 | 5.90 |
| Galveston | Western Gulf | 11.0 | 14.8 |
| Garza | Permian | 7.07 | 5.90 |
| Gillespie | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Glasscock | Permian | 7.07 | 5.90 |
| Goliad | Western Gulf | 11.0 | 14.8 |
| Gonzales | Eagle Ford Shale | 10.5 | 10.0 |
| Gray | Anadarko | 3.15 | 5.87 |
| Grayson | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Gregg | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Grimes | Eagle Ford Shale | 10.5 | 10.0 |
| Guadalupe | Western Gulf | 11.0 | 14.8 |
| Hale | Palo Duro | 7.61 | 9.75 |
| Hall | Palo Duro | 7.61 | 9.75 |
| Hamilton | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hansford | Anadarko | 3.15 | 5.87 |
| Hardeman | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hardin | Western Gulf | 11.0 | 14.8 |
| Harris | Western Gulf | 11.0 | 14.8 |
| Harrison | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Hartley | Palo Duro | 7.61 | 9.75 |
| Haskell | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hays | Western Gulf | 11.0 | 14.8 |
| Hemphill | Anadarko | 3.15 | 5.87 |
| Henderson | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Hidalgo | Western Gulf | 11.0 | 14.8 |
| Hill | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hockley | Permian | 7.07 | 5.90 |

## Table E-1. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Hood | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hopkins | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Houston | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Howard | Permian | 7.07 | 5.90 |
| Hudspeth | Permian | 7.07 | 5.90 |
| Hunt | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Hutchinson | Anadarko | 3.15 | 5.87 |
| Irion | Permian | 7.07 | 5.90 |
| Jack | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Jackson | Western Gulf | 11.0 | 14.8 |
| Jasper | Western Gulf | 11.0 | 14.8 |
| Jeff Davis | Permian | 7.07 | 5.90 |
| Jefferson | Western Gulf | 11.0 | 14.8 |
| Jim Hogg | Western Gulf | 11.0 | 14.8 |
| Jim Wells | Western Gulf | 11.0 | 14.8 |
| Johnson | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Jones | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Karnes | Eagle Ford Shale | 10.5 | 10.0 |
| Kaufman | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Kendall | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Kenedy | Western Gulf | 11.0 | 14.8 |
| Kent | Permian | 7.07 | 5.90 |
| Kerr | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Kimble | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| King | Permian | 7.07 | 5.90 |
| Kinney | Western Gulf | 11.0 | 14.8 |
| Kleberg | Western Gulf | 11.0 | 14.8 |
| Knox | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| La Salle | Eagle Ford Shale | 10.5 | 10.0 |
| Lamar | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Lamb | Palo Duro | 7.61 | 9.75 |
| Lampasas | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Lavaca | Eagle Ford Shale | 10.5 | 10.0 |
| Lee | Eagle Ford Shale | 10.5 | 10.0 |
| Leon | Eagle Ford Shale | 10.5 | 10.0 |
| Liberty | Western Gulf | 11.0 | 14.8 |
| Limestone | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Lipscomb | Anadarko | 3.15 | 5.87 |
| Live Oak | Eagle Ford Shale | 10.5 | 10.0 |
| Llano | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Loving | Permian | 7.07 | 5.90 |
| Lubbock | Permian | 7.07 | 5.90 |
| Lynn | Permian | 7.07 | 5.90 |
| Madison | Western Gulf | 11.0 | 14.8 |

## Table E-1. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Marion | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Martin | Permian | 7.07 | 5.90 |
| Mason | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Matagorda | Western Gulf | 11.0 | 14.8 |
| Maverick | Eagle Ford Shale | 10.5 | 10.0 |
| McCulloch | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| McLennan | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| McMullen | Eagle Ford Shale | 10.5 | 10.0 |
| Medina | Western Gulf | 11.0 | 14.8 |
| Menard | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Midland | Permian | 7.07 | 5.90 |
| Milam | Eagle Ford Shale | 10.5 | 10.0 |
| Mills | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Mitchell | Permian | 7.07 | 5.90 |
| Montague | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Montgomery | Western Gulf | 11.0 | 14.8 |
| Moore | Anadarko | 3.15 | 5.87 |
| Morris | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Motley | Palo Duro | 7.61 | 9.75 |
| Nacogdoches | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Navarro | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Newton | Western Gulf | 11.0 | 14.8 |
| Nolan | Permian | 7.07 | 5.90 |
| Nueces | Western Gulf | 11.0 | 14.8 |
| Ochiltree | Anadarko | 3.15 | 5.87 |
| Oldham | Palo Duro | 7.61 | 9.75 |
| Orange | Western Gulf | 11.0 | 14.8 |
| Palo Pinto | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Panola | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Parker | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Parmer | Palo Duro | 7.61 | 9.75 |
| Pecos | Permian | 7.07 | 5.90 |
| Polk | Western Gulf | 11.0 | 14.8 |
| Potter | Palo Duro | 7.61 | 9.75 |
| Presidio | Permian | 7.07 | 5.90 |
| Rains | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Randall | Palo Duro | 7.61 | 9.75 |
| Reagan | Permian | 7.07 | 5.90 |
| Real | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Red River | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Reeves | Permian | 7.07 | 5.90 |
| Refugio | Western Gulf | 11.0 | 14.8 |
| Roberts | Anadarko | 3.15 | 5.87 |
| Robertson | Eagle Ford Shale | 10.5 | 10.0 |

## Table E-1. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Rockwall | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Runnels | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Rusk | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Sabine | East Texas/Haynesville Shale | 4.22 | 5.92 |
| San Augustine | East Texas/Haynesville Shale | 4.22 | 5.92 |
| San Jacinto | Western Gulf | 11.0 | 14.8 |
| San Patricio | Western Gulf | 11.0 | 14.8 |
| San Saba | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Schleicher | Permian | 7.07 | 5.90 |
| Scurry | Permian | 7.07 | 5.90 |
| Shackelford | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Shelby | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Sherman | Anadarko | 3.15 | 5.87 |
| Smith | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Somervell | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Starr | Western Gulf | 11.0 | 14.8 |
| Stephens | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Sterling | Permian | 7.07 | 5.90 |
| Stonewall | Permian | 7.07 | 5.90 |
| Sutton | Permian | 7.07 | 5.90 |
| Swisher | Palo Duro | 7.61 | 9.75 |
| Tarrant | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Taylor | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Terrell | Marathon Thrust Belt | 7.61 | 9.75 |
| Terry | Permian | 7.07 | 5.90 |
| Throckmorton | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Titus | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Tom Green | Permian | 7.07 | 5.90 |
| Travis | Western Gulf | 11.0 | 14.8 |
| Trinity | Western Gulf | 11.0 | 14.8 |
| Tyler | Western Gulf | 11.0 | 14.8 |
| Upshur | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Upton | Permian | 7.07 | 5.90 |
| Uvalde | Western Gulf | 11.0 | 14.8 |
| Val Verde | Permian | 7.07 | 5.90 |
| Van Zandt | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Victoria | Western Gulf | 11.0 | 14.8 |
| Walker | Western Gulf | 11.0 | 14.8 |
| Waller | Western Gulf | 11.0 | 14.8 |
| Ward | Permian | 7.07 | 5.90 |
| Washington | Western Gulf | 11.0 | 14.8 |
| Webb | Eagle Ford Shale | 10.5 | 10.0 |
| Wharton | Western Gulf | 11.0 | 14.8 |
| Wheeler | Anadarko | 3.15 | 5.87 |

**Table E-1. County-Level VOC Emission Factors**

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Wichita | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Wilbarger | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Willacy | Western Gulf | 11.0 | 14.8 |
| Williamson | Western Gulf | 11.0 | 14.8 |
| Wilson | Eagle Ford Shale | 10.5 | 10.0 |
| Winkler | Permian | 7.07 | 5.90 |
| Wise | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Wood | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Yoakum | Permian | 7.07 | 5.90 |
| Young | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Zapata | Western Gulf | 11.0 | 14.8 |
| Zavala | Eagle Ford Shale | 10.5 | 10.0 |

Updated natural gas speciation profiles were developed through evaluation of GLYCalc emissions inventory reports submitted to TCEQ as part of the annual point source emissions inventory compilation. ERG reviewed TCEQ emissions inventory files and obtained GLYCalc data for 157 sites located in 64 counties across Texas. Using this information, average county natural gas composition profiles were developed. The 64 counties for which data were available were then grouped by basins (Anadarko, Bend Arch-Forth Worth, East Texas, Permian, and Western Gulf Basins), and basin-level average natural gas composition (wet and dry) profiles were calculated. Basin-level average natural gas composition profile and state-level average profiles were then allocated to counties with no data based on which basin the county was located in. For two basins, the Marathon Thrust Belt and Palo Duro, no data was available so a state-level average profile was developed. Table E-2 presents the basin-level and state-level average natural gas stream composition profiles for both wet and dry natural gas streams.

## Table E-2. Basin-Level and State-Level Average Natural Gas Stream Composition Profiles

| Composition in % Volume | Anadarko Basin | | Bend Arch-Fort Worth Basin | | East Texas Basin | | Permian Basin | | Western Gulf | | State Profile | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream |
| Water | 0.04 | 0.13 | 0.01 | 0.12 | 0.01 | 0.12 | 0.01 | 0.15 | 0.01 | 0.12 | 0.01 | 0.12 |
| Carbon Dioxide | 0.64 | 0.65 | 1.74 | 1.74 | 1.72 | 1.71 | 0.95 | 0.90 | 1.13 | 1.14 | 1.43 | 1.44 |
| Hydrogen Sulfide | 0.03 | 0.03 | 0.001 | 0.001 | 0.0004 | 0.0004 | 0.11 | 0.11 | 0.0003 | 0.25 | 0.03 | 0.09 |
| Nitrogen | 1.35 | 1.34 | 1.74 | 1.73 | 0.88 | 0.87 | 2.14 | 2.18 | 0.51 | 0.49 | 1.20 | 1.19 |
| Methane | 90.76 | 90.68 | 87.91 | 87.59 | 91.73 | 91.49 | 80.43 | 78.53 | 90.07 | 89.94 | 88.67 | 88.36 |
| Ethane | 3.99 | 3.98 | 5.23 | 5.21 | 3.57 | 3.64 | 9.02 | 9.07 | 4.51 | 4.51 | 5.03 | 5.00 |
| Propane | 1.74 | 1.74 | 2.14 | 2.18 | 1.04 | 1.06 | 4.48 | 5.39 | 2.04 | 2.05 | 2.13 | 2.21 |
| Isobutane | 0.26 | 0.26 | 0.31 | 0.32 | 0.28 | 0.29 | 0.51 | 0.61 | 0.48 | 0.48 | 0.38 | 0.40 |
| n-Butane | 0.54 | 0.54 | 0.62 | 0.68 | 0.31 | 0.32 | 1.19 | 1.63 | 0.51 | 0.51 | 0.58 | 0.64 |
| Isopentane | 0.16 | 0.16 | 0.20 | 0.22 | 0.15 | 0.17 | 0.35 | 0.40 | 0.24 | 0.24 | 0.22 | 0.23 |
| n-Pentane | 0.17 | 0.17 | 0.27 | 0.29 | 0.11 | 0.12 | 0.32 | 0.44 | 0.17 | 0.17 | 0.20 | 0.22 |
| Cyclopentane | 0.01 | 0.01 | 0.03 | 0.04 | 0.04 | 0.04 | 0.01 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 |
| n-Hexane | 0.10 | 0.06 | 0.05 | 0.12 | 0.05 | 0.05 | 0.16 | 0.18 | 0.05 | 0.06 | 0.06 | 0.09 |
| Cyclohexane | 0.01 | 0.01 | 0.04 | 0.03 | 0.03 | 0.03 | 0.09 | 0.11 | 0.05 | 0.06 | 0.04 | 0.05 |
| Other Hexanes | 0.14 | 0.14 | 0.07 | 0.06 | 0.10 | 0.11 | 0.24 | 0.29 | 0.17 | 0.15 | 0.13 | 0.13 |
| Heptanes | 0.06 | 0.06 | 0.08 | 0.08 | 0.06 | 0.07 | 0.14 | 0.14 | 0.07 | 0.09 | 0.08 | 0.08 |
| Methylcyclohexane | 0.02 | 0.02 | 0.02 | 0.02 | 0.01 | 0.02 | 0.04 | 0.04 | 0.04 | 0.04 | 0.03 | 0.04 |
| Benzene | 0.01 | 0.01 | 0.01 | 0.01 | 0.02 | 0.03 | 0.07 | 0.08 | 0.01 | 0.02 | 0.02 | 0.02 |
| Toluene | 0.01 | 0.01 | 0.003 | 0.003 | 0.01 | 0.01 | 0.04 | 0.04 | 0.01 | 0.02 | 0.01 | 0.01 |
| Ethylbenzene | 0.001 | 0.001 | 0.0005 | 0.001 | 0.001 | 0.001 | 0.01 | 0.01 | 0.001 | 0.002 | 0.001 | 0.002 |
| Xylenes | 0.003 | 0.01 | 0.002 | 0.003 | 0.002 | 0.005 | 0.01 | 0.01 | 0.003 | 0.01 | 0.003 | 0.005 |
| C8+ Heavies | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.04 | 0.07 | 0.07 | 0.11 | 0.11 | 0.06 | 0.06 |

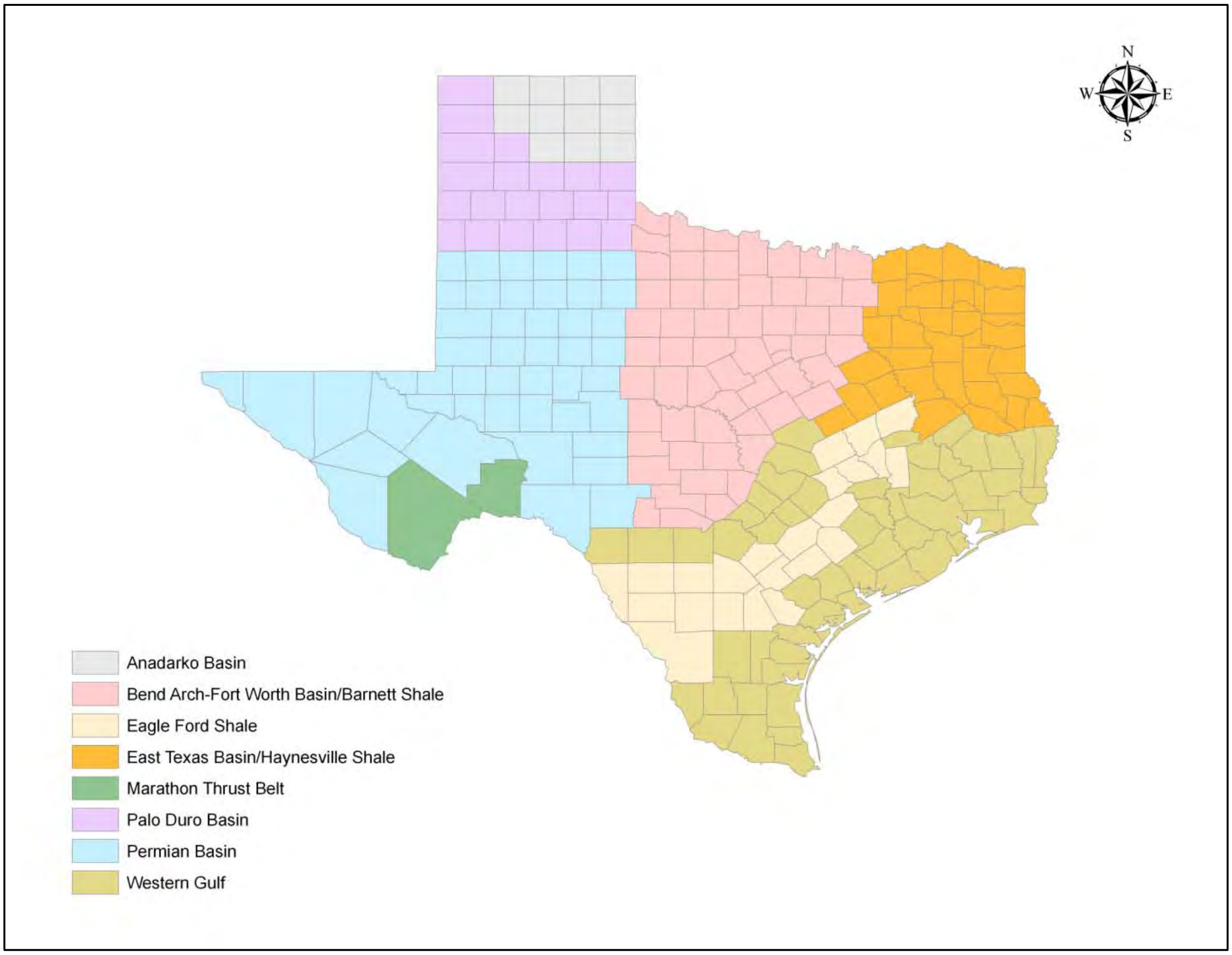
# 1.0 Introduction

Under contract with the Texas Commission on Environmental Quality (TCEQ), Eastern Research Group, Inc. (ERG) developed refined emission factors for volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions from condensate tanks, as well as improved gas speciation profiles for different gas formations on a county-by-county basis. This information will be used to improve area source emissions inventory estimates for the oil and gas sector. This report describes ERG's findings relative to an analysis of existing condensate tank emissions data, survey efforts to collect additional condensate tank emissions data, and development of natural gas speciation profiles in Texas.

# 2.0 VOC Emissions From Condensate Storage Tanks

A review of available literature was conducted for data on emissions testing and emissions estimates for condensate tanks in Texas. In addition, data collected in the Barnett Shale Area Special Inventory was evaluated, a phone survey of Texas condensate producers was conducted, and additional data on emissions estimates was obtained from TCEQ as available. ERG evaluated this data for its relevance and quality, and derived region-specific emission factors for eight geographic regions in the state. These eight regions are shown in Figure 2-1.

**Figure 2-1. Condensate Producing Regions in Texas**




## 2.1 Condensate Production

Condensate, for purposes of this survey, is defined as a hydrocarbon liquid produced at an oil or gas well and having an American Petroleum Institute (API) gravity greater than

40 degrees.[1] The API gravity of crude oil/condensate can vary from 20 to 70 degrees. In practice, most producers do not distinguish between oil and condensate, calling any petroleum liquid "oil". However, the API gravity of produced liquid is important, as a petroleum liquid with a higher API gravity will generally command a premium in the market.[2] API gravity is also important in determining what calculation method should be used to estimate the VOC emissions associated with the production of a hydrocarbon liquid. The Texas Railroad Commission (RRC) distinguishes between oil and condensate, with 'oil' being the liquid produced at oil wells and 'condensate' being the hydrocarbon liquid produced at gas wells.

TCEQ's area source emissions estimate is based upon county-level oil and condensate production as reported on the RRC website. When creating an area source emissions estimate, it is important to distinguish between the emissions from petroleum liquid storage tanks located at 'oil' wells, and the emissions from petroleum liquid storage tanks located at 'gas' wells because the VOC emission factor for tanks at oil wells (1.6 pounds (lbs) VOC/barrel (bbl)) is significantly lower than the emission factor historically used for tanks at gas wells (33.3 lbs VOC/bbl).[3] Given the difference in these estimates, it is important to distinguish between oil and condensate.

The RRC county level production data shows that the majority of petroleum-producing counties produce both 'oil' and 'condensate'. This is usually due to the fact that, within the geographic boundary of many counties, there may be two or more petroleum producing formations stacked atop one another at different depths below ground. One of the formations may produce oil, while the other may produce gas, while perhaps a third formation yields gas from shale. Therefore, the estimates of emissions from any particular county or region could reflect the emissions from wells tapping one, two, or more petroleum-producing formations underground.

## 2.2 Literature Review

ERG reviewed the current literature for existing studies and other sources that evaluated emissions from oil and condensate tanks in Texas. These studies included emissions measured via testing, emissions estimated through the use of software programs using

[1] The American Petroleum Institute (API) does not define condensate in terms of its API gravity. The State of Colorado defines condensate as a hydrocarbon liquid that has an API gravity greater than or equal to 40° API at 60°F. Colorado Department of Public Health and Environment, PS Memo 05-01, Oil and Gas Atmospheric Condensate Storage Tank Batteries, Regulatory Definitions and Permitting Guidance, October 1, 2009. http://www.cdphe.state.co.us/ap/down/ps05-01.pdf

[2] Well Servicing Magazine, "Crude Oil Testing", Andy Maslowski, September/October 2009, http://wellservicingmagazine.com/crude-oil-testing

[3] These emission factors were used for estimating emissions from upstream area sources in the oil and gas industry in the report "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions", TCEQ, 11/24/2010. The emission factors were first developed in the 2006 HARC study "VOC Emissions From Oil and Condensate Storage Tanks".

equations-of-state, and comparisons of measured emissions with estimated emissions. The data in these studies were analyzed for their validity and utility, and a refined emission factor for estimating emissions from condensate storage tanks was developed. A brief description follows of the available literature, the information they contain, and the information from the study used in developing updated emission factors.

### 2.2.1 Emissions Data Derived from Testing

This section examines studies where emissions data was generated via direct measurement (testing) of emissions from oil and condensate tanks.

"*VOC Emissions from Oil and Condensate Storage Tanks*" (Houston Advanced Research Center (HARC), 2006, and Texas Environmental Research Consortium (TERC), 2009).[4]

This study is widely referred to as the "HARC" or "HARC H051C" study. In this study, researchers examined 2 oil and 13 gas (condensate) sites in the Fort Worth basin, and 9 oil and 9 gas sites in the Western Gulf basin. This study measured oil and condensate tank emissions from each site and includes information such as API gravity and separator pressure. The HARC 2006 study noted that the emission estimates had a high uncertainty, due in part to the very low condensate production rates at well sites in Parker and Denton counties. The HARC 2006 study also noted that these measurements were taken during a period when recorded daytime high temperatures ranged from 98 to 107 degrees Fahrenheit at the nearby Dallas-Fort Worth Airport. The VOC emission factor of 33.3 lbs VOC/bbl condensate and the HAP emission factors used in TCEQ's 2008 upstream oil and gas area source inventory are derived from this report.

API provided comments[5] to the U.S. Environmental Protection Agency (EPA) on the derivation of this emission factor in their comments on EPA's proposed changes to the New Source Performance Standard (NSPS) for Oil and Gas Production (Subpart OOOO) on November 30, 2011.[6] API called into question the validity of two of the data points used in developing the emission factor. API also questioned the use of emissions data from several sites where the measured condensate production was minimal. API noted in their comments that the 24-hour production measurement methodology used in the HARC study (manual gauging of oil level in the tank) may be subject to error, as the onsite measurements for two barrels of production would require accurately

[4] Houston Advanced Research Center, VOC Emissions from Oil and Condensate Storage Tanks, October 31, 2006. http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf

[5] The API comments relative to condensate storage tank emissions were made by Dr. Ed Ireland of the Barnett Shale Energy Education Council.

[6] American Petroleum Institute, API Comments on the Proposed Rulemaking – Oil and Gas Sector Regulations, November 30, 2011, http://www.api.org/Newsroom/testimony/upload/2011-11-30-API-Oil-and-Gas-Rule-Final-Comments-Text.pdf

determining a difference of 0.71 to 1.2 inches in oil level via manual gauging of these 300 bbl condensate tanks.[7] However, in the 2009 revisions to the original report, the study authors noted that daily average production rates during the sampling period were obtained from site operating logs, not manual measurement as first erroneously reported.

API also questioned the presumption that emissions are solely a function of throughput and presented evidence that the VOC emissions per barrel of condensate produced are a non-linear function, dependent primarily upon separator pressure, and, to a lesser extent, API gravity. The comments suggest that each well/tank combination has unique emissions, based on: the composition of the liquids and gas produced, the API gravity of the liquid, the types of separator equipment in use, and the operating parameters of the separator. In general, liquids with a higher API gravity tend to have higher flash emissions per barrel than liquids with a lower API gravity. Also, the larger the pressure drop at the last stage of liquid-gas separation prior to moving the liquid to the storage tank, the higher the flash emissions. Therefore, any emission factor that is dependent solely upon production and does not take these other factors into account may not accurately estimate emissions for a specific well/tank combination.

While such a multivariate approach is feasible for estimating point source emissions at any individual location, this approach would be impractical for estimating county-level, area source emissions where site-specific operating data is not readily available. The approach used by this study overcomes these limitations and provides a reasonably accurate means for estimating emissions from the condensate-producing regions of Texas by developing regional emission factors based on testing data and emissions estimates developed using TCEQ's published preferred methodologies.

ERG re-examined the data from all 33 oil and condensate sites examined in the HARC 2006 study. Although 27 sites produce liquids having an API gravity of 40 degrees or greater, only data from the 22 sites designated as producing condensate have been considered in this analysis. In this re-analysis, three additional data points were removed from the data set. Data for tank 17 was removed because the calculated flash emissions (145 pounds VOC per barrel condensate produced (lbs/bbl)) indicated that 55% of the condensate flashed when reduced in pressure from 200 pounds per square inch gauge (psig). Data for tank 25 was removed because the calculated flash emissions (215 lbs/bbl) indicated that 82% of the condensate flashed when reduced in pressure from 200 psig. According to API, neither of these flash emission values is possible at this separator pressure.[6] Data for tank 26 was also removed from the dataset, as the recorded emissions (1,217.6 lbs/bbl) seem to indicate an equipment failure (such as a

[7] Information in Appendix A of the study report indicates that, for the sites having production of two or less barrels of condensate per day, condensate was stored in a single 300 BBL capacity tank. 300 BBL oil tanks typically come in 12 foot and 15.5 foot diameters, and have capacities of 1.68 bbl/inch and 2.8 bbl/inch, respectively.

separator dump valve stuck in the open position) or a measurement error as a 42 gallon barrel of condensate weighs approximately 270 pounds. An emission factor for each of the remaining 19 sites was calculated. Table 2-1 shows the emissions measurement data from the HARC 2006 study.

**Table 2-1. Condensate Tank Emission Data from the HARC 2006 Study**

| Tank Battery | County | Region | API Gravity | Separator Discharge Pressure (psi) | VOC (lbs/day) | Production (bbl/day) | VOC Emission Factor (lbs/bbl) |
|---|---|---|---|---|---|---|---|
| 2 | Montgomery | Western Gulf | 42 | 41 | 383.2 | 105 | 3.65 |
| 3 | Montgomery | Western Gulf | 41 | 38 | 688.9 | 87 | 7.92 |
| 4 | Montgomery | Western Gulf | 40 | 34 | 93.7 | 120 | 0.78 |
| 5 | Montgomery | Western Gulf | 43 | 46 | 67.4 | 100 | 0.67 |
| 6 | Montgomery | Western Gulf | 39 | 33 | 384.7 | 130 | 2.96 |
| 13 | Denton | Fort Worth | 61 | 200 | 78.5 | 2 | 39.25 |
| 14 | Denton | Fort Worth | 59 | 200 | 118 | 4 | 29.50 |
| 15 | Denton | Fort Worth | 61 | 200 | 60 | 5 | 12.00 |
| 16 | Denton | Fort Worth | 61 | 200 | 121.2 | 2 | 60.60 |
| 18 | Denton | Fort Worth | 58 | 200 | 73.4 | 10 | 7.34 |
| 19 | Denton | Fort Worth | 58 | 200 | 26.3 | 2 | 13.15 |
| 20 | Denton | Fort Worth | 59 | 200 | 304.3 | 10 | 30.43 |
| 23 | Parker | Fort Worth | 48 | 39 | 150.2 | 27 | 5.56 |
| 24 | Parker | Fort Worth | 41 | 36 | 4.2 | 1 | 4.20 |
| 27 | Denton | Fort Worth | 59 | 200 | 28.8 | 2 | 14.40 |
| 28 | Brazoria | Western Gulf | 46 | 38 | 125.2 | 30 | 4.17 |
| 29 | Brazoria | Western Gulf | 42 | 41 | 2,055 | 61 | 33.69 |
| 30 | Brazoria | Western Gulf | 42 | 36 | 91.6 | 15 | 6.11 |
| 32 | Galveston | Western Gulf | 48 | 121 | 9,016 | 142 | 63.49 |

The production-weighted average emission factor for these 19 condensate tanks is 16.22 lbs/bbl, whereas the arithmetic average is 17.89 lbs/bbl. The production-weighted approach reduces the effect of measurement error (as noted in the API comments) on the emissions estimate, as the error attributable to measurement error from tanks with very low production has minimal 'weight' in the computation of the overall estimate.

### 2.2.2 Comparisons of Emissions Data Derived from Testing with Emissions Estimates Derived from Models/Software Programs

There is only a small amount of data from testing available at present. Emission estimates derived through use of emissions estimation software utilizing equations-of-state can provide useful information in developing regional emission factors. Therefore, emissions data estimated with software and models were used to supplement the existing testing data.

This section examines two studies where researchers conducted emissions testing on tanks and then generated emission estimates for those same tanks using models or software programs.

"*Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation*" (TCEQ, 2009)

This 2009 study conducted by Hy-Bon Engineering for TCEQ compared actual measured emissions from 30 test sites to estimated emissions from those same sites. Emissions estimates were created using onsite data and several different emissions estimating models and software[8]. At each test site, extensive data was taken on tanks and equipment, operating parameters, environmental conditions, and liquids production. Liquid and gas samples were taken for lab analysis and direct measurements were taken of vapors vented. The measured emissions from the 30 test sites were then compared to the estimated emissions from those same sites.

This report concludes that the calculated emissions using the E&P Tank – AP 42 model typically overestimated measured emissions in 85.7% of the cases, while the E&P Tank - RVP model overestimated emissions for 82.1% of the cases. Calculated emissions using HYSYS Process Simulation software overestimated measured emissions in 64.3% of the cases. Therefore, it was assumed that emissions estimated using E&P Tank – AP 42, E&P Tank – RVP, or HYSYS may over-estimate emissions, and are conservative. This same study showed that the Gas/Oil Ratio (GOR) method in combination with Tanks 4.09 underestimated flashing, breathing and working emissions in 76.7% of the cases. Therefore, any information obtained that utilizes the GOR method to estimate emissions will be, on average, an underestimate of the actual emissions. TCEQ has issued guidance[9] stating that testing, the various process simulation software packages, E&P Tank, and GOR, in combination with site sampling and analysis, are the preferred methods for estimating flash emissions, in order of most preferred to least preferred.

There are eleven sites out of the thirty whose API gravity is less than 40 degrees, the lower bound for condensate in this study. Therefore, data from these eleven sites will

[8] The emissions estimation methods used in this study include: E&P TANK 2.0, AspenTech HYSYS 2006.5, GRI-HapCalc 3.0, the Environmental Consultant Research (EC/R) Algorithm, Vasquez-Beggs Correlation, Gas-Oil Ratio (GOR), and Valko-McCain Correlation. TANKS 4.09 was used to estimate breathing and working emissions for the GOR, Vasquez-Beggs, and Valko-McCain methods, which only calculate flash emissions.

[9] "Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites", APDG 5942, May 2012, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf

not be considered. Emissions measurement data from the 19 remaining sites in this report are shown in Table 2-2.

The production-weighted average emission factor from testing for all of these sites is 4.59 lbs/bbl of condensate, whereas the arithmetic average is 11.0 lbs/bbl. The emission measurement tests on these tanks were conducted during the months of July, August, and September.

**Table 2-2. Operating Parameters, Production, and Measured Emissions**

| Site ID # | County | Region | API Gravity (deg.) | Separator Pressure (psia) | Liquid Production (bbl/day) | VOC Emissions (ton/yr) | VOC Emission Factor (lbs/bbl) |
|---|---|---|---|---|---|---|---|
| WTB# 1 | Ector | Permian | 43.7 | 83.82 | 976 | 1134.9 | 6.37 |
| WTB# 4 | Terrell | Permian | 50 | 88.82 | 34 | 12.6 | 2.03 |
| WTB# 5 | Terrell | Permian | 48.3 | 103.82 | 18 | 53 | 16.1 |
| WTB# 11 | Crane | Permian | 42.8 | 33.82 | 250 | 72 | 1.58 |
| WTB# 15 | Martin | Permian | 40.6 | 30.82 | 332 | 98.8 | 1.63 |
| WTB# 17 | Martin | Permian | 41.4 | 35.82 | 166 | 13.1 | 0.43 |
| WTB# 19 | Ector | Permian | 42.8 | 73.82 | 1979 | 1790 | 4.96 |
| WTB# 23 | Andrews | Permian | 43.3 | 53.82 | 327 | 93.5 | 1.57 |
| NTB# 1 | Ochiltree | Anadarko | 44.8 | 62.14 | 69 | 36.7 | 2.91 |
| NTB# 2 | Hansford | Anadarko | 45.3 | 48.44 | 74 | 8.3 | 0.62 |
| NTB# 3 | Hansford | Anadarko | 42.3 | 40.44 | 98 | 6.9 | 0.386 |
| NTB# 5 | Ochiltree | Anadarko | 67.5 | 44.44 | 50 | 154.8 | 17.0 |
| NTB# 6 | Denton | Fort Worth | 55.7 | 158.44 | 13 | 19.3 | 8.14 |
| NTB# 7 | Wise | Fort Worth | 58.6 | 161.44 | 34 | 38.1 | 6.14 |
| NTB# 8 | Wise | Fort Worth | 58.9 | 139.44 | 16 | 100.3 | 34.3 |
| NTB# 9 | Wise | Fort Worth | 55.2 | 167.44 | 12 | 38.6 | 17.6 |
| NTB# 11 | Wise | Fort Worth | 63.7 | 245.44 | 5 | 71.5 | 78.4 |
| NTB# 12 | Wise | Fort Worth | 63.7 | 239.44 | 14 | 14.8 | 5.79 |
| NTB# 13 | Wise | Fort Worth | 56.2 | 139.44 | 62 | 39.3 | 3.47 |

Table 2-3 shows the estimated emission factors for the 19 test sites using the methods preferred by TCEQ. The emissions factor based on measured emissions is also included for comparison purposes.

## Table 2-3. Comparison of Estimated Emissions with Measured Emissions

| Site ID # | County | Liquid Production (bbl/day) | VOC Emission Factors (lbs/bbl) | | | | |
|---|---|---|---|---|---|---|---|
| | | | Testing | E&P TANK - AP 42 LPO | E&P TANK - RVP LPO | HYSYS | GOR + TANKS 4.09 |
| WTB# 1 | Ector | 976 | 6.37 | 24.67 | 37.41 | 13.42 | 1.99 |
| WTB# 4 | Terrell | 34 | 2.03 | 14.83 | 17.89 | 8.70 | 9.15 |
| WTB# 5 | Terrell | 18 | 16.13 | 12.48 | 14.61 | 8.16 | 6.03 |
| WTB# 11 | Crane | 250 | 1.58 | 8.90 | 19.66 | 8.97 | 0.48 |
| WTB# 15 | Martin | 332 | 1.63 | 13.04 | 18.07 | 6.88 | 0.61 |
| WTB# 17 | Martin | 166 | 0.43 | 20.76 | 35.35 | 15.72 | 0.86 |
| WTB# 19 | Ector | 1979 | 4.96 | 30.52 | 55.26 | 22.69 | 4.51 |
| WTB# 23 | Andrews | 327 | 1.57 | 46.60 | 55.48 | 42.44 | 1.79 |
| NTB# 1 | Ochiltree | 69 | 2.91 | 9.69 | 26.13 | 11.91 | 1.23 |
| NTB# 2 | Hansford | 74 | 0.62 | 9.70 | 17.92 | 7.26 | 0.32 |
| NTB# 3 | Hansford | 98 | 0.39 | 12.52 | 26.50 | 4.98 | 1.59 |
| NTB# 5 | Ochiltree | 50 | 16.96 | 53.81 | 59.84 | 4.71 | 13.63 |
| NTB# 6 | Denton | 13 | 8.14 | 13.49 | 24.03 | 12.64 | 2.74 |
| NTB# 7 | Wise | 34 | 6.14 | 8.22 | 17.57 | 1.77 | 1.43 |
| NTB# 8 | Wise | 16 | 34.35 | 15.07 | 26.37 | 3.77 | 4.28 |
| NTB# 9 | Wise | 12 | 17.63 | 37.44 | 72.60 | 4.57 | 27.03 |
| NTB# 11 | Wise | 5 | 78.36 | 12.60 | 17.53 | 8.77 | 4.60 |
| NTB# 12 | Wise | 14 | 5.79 | 18.79 | 24.27 | 2.74 | 9.00 |
| NTB# 13 | Wise | 62 | 3.47 | 25.98 | 30.58 | 0.53 | 8.15 |

It is instructive to see how much the various emissions estimation methods over-estimate or under-estimate emissions when compared to measured emissions values. This can help place the estimates generated via emissions estimation methods in context with the measured emissions, and give a sense of their value in estimating actual emissions from condensate tanks. Table 2-4 shows the ratio that the various estimation models over- or under- estimated emissions. The ratio is presented as (estimated emission/measured emission). A ratio of 1 indicates the estimate is in perfect agreement with the measurement, whereas a ratio of 10 indicates the estimated emission rate is ten times higher than the measured emission rate. A ratio of 0.5 indicates the estimated emissions are half of the measured emissions, while a ratio of 0.1 indicates the estimated emissions are 1/10th of the measured emissions. For simplicity, some values have been rounded.

**Table 2-4. Ratio Between Estimated Emissions and Measured Emissions**

| Site ID # | Emission Factor From Measurement (lbs/bbl) | Ratio of Over Estimate or Under Estimate | | | |
|---|---|---|---|---|---|
| | | E&P TANK - AP 42 LPO | E&P TANK - RVP LPO | HYSYS | GOR + Tank 4.09 |
| WTB# 1 | 6.37 | 4.0 | 6.0 | 2.0 | 0.3 |
| WTB# 4 | 2.03 | 7.0 | 9.0 | 4.3 | 4.5 |
| WTB# 5 | 16.13 | 0.8 | 0.9 | 0.5 | 0.4 |
| WTB# 11 | 1.58 | 5.6 | 12.5 | 5.7 | 0.3 |
| WTB# 15 | 1.63 | 8.0 | 11 | 4.0 | 0.4 |
| WTB# 17 | 0.43 | 48 | 82 | 36 | 2.0 |
| WTB# 19 | 4.96 | 6.0 | 11 | 4.6 | 0.9 |
| WTB# 23 | 1.57 | 30 | 35 | 27 | 1.1 |
| NTB# 1 | 2.91 | 3.3 | 9.0 | 4.0 | 0.4 |
| NTB# 2 | 0.62 | 16 | 29 | 12 | 0.5 |
| NTB# 3 | 0.39 | 32 | 69 | 13 | 4.0 |
| NTB# 5 | 16.96 | 3.0 | 3.5 | 0.3 | 0.8 |
| NTB# 6 | 8.14 | 1.7 | 3.0 | 1.6 | 0.3 |
| NTB# 7 | 6.14 | 1.3 | 3.0 | 0.3 | 0.2 |
| NTB# 8 | 34.35 | 0.4 | 0.8 | 0.1 | 0.1 |
| NTB# 9 | 17.63 | 2.0 | 4.0 | 0.3 | 1.5 |
| NTB# 11 | 78.36 | 0.2 | 0.2 | 0.1 | 0.1 |
| NTB# 12 | 5.79 | 3.0 | 4.0 | 0.5 | 1.6 |
| NTB# 13 | 3.47 | 7.5 | 9.0 | 0.2 | 2.3 |
| | Average | 9.5 | 15.9 | 6.1 | 1.1 |

As can be seen in the table, the discrepancy between the estimated emissions and measured emissions is quite high. Only 18% of these estimates are within the range of half to twice (0.5 to 2) of the actual measured value. In this comparison, the emissions estimation models are shown to be inconsistent.

"*Upstream Oil and Gas Tank Emission Measurements*" (TCEQ, 2010)

This 2010 study conducted by TCEQ examined 7 gas wells/condensate tank sites in the Barnett Shale. This study compared actual measured emissions to estimated emissions using an emissions estimations model (E&P TANK). The research team collected extensive information on the equipment, operating parameters, production, and vented emissions. Vented emissions were measured with both a thermal mass flow meter and an ultrasonic flow meter. Samples of vent gas were collected and analyzed at two different labs. Production of water and condensate were measured. VOC emission rates and emission factors were calculated using this data. Liquid samples were collected from the pressurized separators and analyzed in a lab. The lab data on the pre-flash liquid composition and equipment operating parameter data were used as inputs to E&P TANK software, and emissions were estimated.

This study is notable for its duplication of all critical measurements and analyses. However, only three of the wells produced condensate during the study period. One of those wells produced only one barrel of condensate, and this production was measured with manual gauging of two tanks of unknown size operating in parallel. The accuracy of this measurement could be subject to the same questions about measurement precision noted by API in their comments on the 2006 HARC study.[10] The other four wells produced no condensate, but VOC emissions were measured from the associated produced water tanks at two of these sites. The study was conducted in July 2010, and the average ambient temperatures recorded on the sites ranged from 74.8 to 86.3 degrees Fahrenheit.

In Table 2-5, the VOC emissions are calculated for the three tanks having condensate production. This table shows the emissions measured using the production data from the thermal mass flow meter and the ultrasonic flow meter. The emissions estimated using E&P TANK are also shown.

If the emissions data from the three sites that produced condensate are averaged using a production-weighted average of the data from the two measurement methods, the average emission factor from both the measurement methods is 12.11 lbs VOC/bbl condensate, whereas the arithmetic average for these three sites from both the measurement methods is 17.52 lbs VOC/bbl condensate. In this study, the estimates of emissions produced with the E&P TANK model varied significantly from the values for actual measured emissions.

### 2.2.3 Emissions Estimates Derived Solely from Models/Software Programs

This section examines a study which provided a set of emission estimates that were generated using only models or software programs.

*"Control of VOC Flash Emissions from Oil and Condensate Storage Tanks in East Texas"* (TCEQ, 2010)

This 2010 study conducted by TCEQ assessed the impact of Title 30 Texas Administrative Code 115.112(d)(5) on the implementation of VOC control devices on oil and condensate tanks in the Houston-Galveston-Brazoria (HGB) ozone nonattainment area. In this study, producers in the target areas were surveyed to assess the number of

[10] American Petroleum Institute, API Comments on the Proposed Rulemaking – Oil and Gas Sector Regulations, November 30, 2011, http://www.api.org/Newsroom/testimony/upload/2011-11-30-API-Oil-and-Gas-Rule-Final-Comments-Text.pdf

## Table 2-5. Condensate Tank Emission Factors from the TCEQ 2010 Study

| Tank Battery | County | Region | API Gravity | Separator Pressure (psi) | Production (bbl/day) | Measured with Thermal Mass Flow Meter | | Measured with Ultrasonic Mass Flow Meter | | Estimated with E&P TANK |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | VOC Emissions (lbs/day) | VOC Emission Factor (lbs/bbl) | VOC Emissions (lbs/day) | VOC Emission Factor (lbs/bbl) | VOC Emission Factor (lbs/bbl) |
| Gage Pitts | Wise | Fort Worth | 61.2 | 171 | 58.5 | 717.9 | 12.3 | 639.9 | 10.9 | 11.5 |
| Waggoner Crystelle | Wise | Fort Worth | 61.2 | 119 | 3.34 | 12.7 | 3.8 | 105.3 | 31.5 | 7.6 |
| First Baptist Church Slidell No.1 | Wise | Fort Worth | 51 | NR | 1 | 11.3 | 11.3 | 35.3 | 35.3 | 0.7 |

tanks that were controlled and the type of controls installed. Although this report does not include any new emissions measurements, it is valuable as it contains E&P TANK and HYSYS reports for 21 condensate batteries in the Haynesville Shale area. One company provided a summary of VOC emissions calculated using E&P TANK run with site-specific sampling inputs for 13 condensate tank batteries in the Haynesville Shale area.

Another company provided emissions estimated using the HYSYS Version 2006.5 process simulator for eight natural gas condensate tank batteries in the Haynesville Shale. These estimates are shown in Table 2-6. As no production figures were given, a production-weighted average cannot be calculated. The arithmetic average is 5.80 lbs VOC/ bbl condensate.

**Table 2-6. Producer-Supplied VOC Emission Estimates for Condensate Tank Batteries in Haynesville Shale Area**

| Site Number | Region | Separator Pressure (psig) | Separator Temperature (°F) | API Gravity @ 60°F | Estimation Model | VOC Emissions (lbs/bbl) |
|---|---|---|---|---|---|---|
| 1 | Haynesville Shale | 45 | 80 | 50.6 | E&P TANK | 2.67 |
| 2 | | 40 | 80 | 49.6 | E&P TANK | 8.45 |
| 3 | | 25 | 86 | 54.2 | E&P TANK | 5.38 |
| 4 | | 95 | 89 | 55.4 | E&P TANK | 1.67 |
| 5 | | 16 | 97 | 59.5 | E&P TANK | 1.09 |
| 6 | | 30 | 70 | 55.3 | E&P TANK | 1.45 |
| 7 | | 60 | 78 | 64.6 | E&P TANK | 8.91 |
| 8 | | 120 | 89 | 55.0 | E&P TANK | 10.24 |
| 9 | | 95 | 80 | 55.0 | E&P TANK | 11.97 |
| 10 | | 60 | 75 | 52.4 | E&P TANK | 4.62 |
| 11 | | 80 | 72 | 57.0 | E&P TANK | 3.98 |
| 12 | | 120 | 85 | 55.0 | E&P TANK | 11.97 |
| 13 | | 60 | 77 | 53.8 | E&P TANK | 3.49 |
| 14 | | 40 | 85 | N/A | HYSYS | 1.16 |
| 15 | | 108 | 98 | N/A | HYSYS | 0.31 |
| 16 | | 752 | 82 | N/A | HYSYS | 15.84 |
| 17 | | 76 | 90 | N/A | HYSYS | 0.32 |
| 18 | | 110 | 80 | N/A | HYSYS | 0.85 |
| 19 | | 690 | 70 | N/A | HYSYS | 14.79 |
| 20 | | 560 | 98 | N/A | HYSYS | 0.73 |
| 21 | | 230 | 90 | N/A | HYSYS | 11.83 |
| | | | | Average | | 5.80 |

### 2.2.4 Other Studies

The following study was evaluated for its utility in contributing estimates for the regional emission factors being developed in this study.

"*Recommendations for Improvements to the CENRAP State's Oils and Gas Emissions Inventories*" (Central Regional Air Planning Association (CENRAP), 2008)

This report contains emission factors for flashing, working, and breathing emissions for condensate tanks in the Anadarko basin. The CENRAP 2008 report states that this emission factor (13.86 lbs VOC/bbl) was obtained from the Independent Petroleum Association of Mountain States (IPAMS)/Western Regional Air Partnership (WRAP) Phase III work (Bar-Ilan, et al, 2008). The IPAMS/WRAP Phase III report states that the emission factors were derived from producer surveys conducted in 2008, but this information and the emission factor could not be verified. The CENRAP 2008 report also contains an emission factor for flashing, working, and breathing emissions from condensate tanks in the East Texas, Western Gulf, Fort Worth, and Permian basins. However, as this emission factor (33.3 lbs VOC/bbl) was taken from the HARC H051C study, it will not be used. Therefore, the emission factors from the CENRAP 2008 report will not be used.

## 2.3 Emission Factor Development Using the Barnett Shale Area Special Inventory, Phase II (2009)

TCEQ provided ERG with data from the "Barnett Shale Area Special Inventory, Phase II 2009" (Barnett Shale Inventory) information in spreadsheet format. The Barnett Shale Inventory data contains 2,268 records with reported condensate production rates and calculated VOC emissions. The VOC emissions were estimated using a variety of methods, including direct measurement of tank emissions, test data, and flash emission and working and breathing emissions models. ERG analyzed this data and developed emission factors for condensate tanks in the Bend-Arch-Fort Worth and Barnett Shale counties.

The original data from 4 separate spreadsheet pages was uploaded into an Access database so that data for individual facilities could be joined into one record. The data was then downloaded back into Excel for analysis. Records were sorted to remove: all records using non-preferred emission estimations methods (Vasquez-Beggs equation, derived emission factors, and HARC H051C emission factor), all records where condensate tank emissions were equal to zero, and all records where annual throughput of condensate was equal to zero. Individual records were examined for internal consistency, and were rejected if the recorded site values for annual throughput were not equal to condensate production. Emission factors were calculated using the values for emissions and throughput. All records with emission factors above 140 lbs/bbl were rejected, as it was deemed that emissions above 50% of the weight of produced condensate were indicative of equipment malfunction or an error in the data, estimating method, or record. The records were then sorted by estimation method. Records in which the estimation method was not noted were not analyzed, as these records lacked critical information for determining their usefulness and accuracy. Both a production-weighted average and an arithmetic average emission factor, before controls, were calculated for each of the emission estimation methods. The percent of total production that is reported in the special inventory as controlled was also calculated. The results are presented in Table 2-7.

The production-weighted average of the emission factors developed using the estimation methods preferred by TCEQ is 6.77 lbs/bbl, before the effect of controls. The arithmetic average of the emission factors developed using the estimation methods preferred by TCEQ is 12.95 lbs/bbl, before the effect of controls. As discussed in the report "*Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation*", the E&P TANK and the Process Simulator models tended to produce higher emission estimates, while the GOR method produced lower estimates. This is reflected in the Barnett Shale Inventory data; the emission estimates generated with E&P TANK (6.58, 6.71, and 10.13 lbs/bbl) and process simulator models (7.51 lbs/bbl) are generally, but not always, higher than the emission estimates generated using the GOR method (3.96 and 8.12 lbs/bbl).

**Table 2-7. Condensate Tank VOC Emission Factors by Method – Barnett Shale Inventory**

| Flash Emission Calculation Method | Working and Breathing Emission Calculation Method | Total Production (bbl) | Number of Sources (Count) | Production-Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) | % of Production Controlled |
|---|---|---|---|---|---|---|
| Process Simulator Models | EPA TANKS Program | 62,112 | 32 | 7.51 | 10.8 | 0% |
| E&P TANK | Other: | 112,651 | 142 | 6.58 | 23.3 | 7.7% |
| E&P TANK | EPA TANKS Program | 94,544 | 29 | 6.71 | 13.5 | 15.2% |
| E&P TANK | E&P TANK | 947,655 | 918 | 10.13 | 12.9 | 0.26% |
| GOR Method | EPA TANKS Program | 74,652 | 36 | 8.12 | 9.60 | 6.71% |
| GOR Method | E&P TANK | 1,175,194 | 407 | 3.96 | 9.87 | 25.8% |
| Direct Measurement of Emissions | Other: | 12,601 | 11 | 7.82 | 13.3 | 0% |
| Preferred Methods | Totals | 2,479,409 | 1,575 | 6.77 | 12.95 | 13.5% |

One survey respondent indicated that they used direct measurement to estimate emissions, but, since no other details were given, these data points were treated as being calculated by a preferred method.

The Barnett Shale Inventory data was also sorted by county, and emission factors for condensate tanks were developed at the county level. The data analysis was similar to that done for the entire Barnett Shale region. Emission factors were created using the values for emissions and throughput. The records were then sorted by estimation method, and only records using the preferred estimation methods for flashing emissions (direct measurement, process simulator, E&P Tank, GOR) were analyzed. Records in which the estimation method was unknown were not analyzed. Records were then sorted by county. A production-weighted average emission factor, and an arithmetic average of the emission factors, before controls, was calculated for each of the counties. The results are presented in Table 2-8.

**Table 2-8. Condensate Tank VOC Emission Factors by County – Barnett Shale Inventory**

| Emission Calculation Methods | County | Total Production (bbl) | Number of Sources (Count) | Production-Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) | % of Production Controlled |
|---|---|---|---|---|---|---|
| Flash Emissions: Process Simulator Models, E&P Tank, Direct Measurement, GOR<br><br>Working and Breathing Emissions: E&P Tank, EPA TANKS Program, Other | Clay | 6,404 | 3 | 3.83 | 7.10 | 0.0% |
| | Cooke | 155,352 | 41 | 4.15 | 4.53 | 35.7% |
| | Denton | 180,295 | 226 | 9.51 | 13.98 | 2.6% |
| | Erath | 35,520 | 72 | 16.88 | 18.75 | 0.0% |
| | Hood | 199,738 | 183 | 7.70 | 12.10 | 1.9% |
| | Jack | 62,590 | 40 | 4.86 | 8.57 | 0.0% |
| | Johnson | 62,207 | 71 | 9.77 | 16.74 | 3.5% |
| | Montague | 588,385 | 135 | 3.55 | 5.39 | 42.1% |
| | Palo Pinto | 333,620 | 53 | 2.25 | 5.14 | 0.2% |
| | Parker | 164,973 | 231 | 10.70 | 13.58 | 5.6% |
| | Somervell | 6,753 | 23 | 10.24 | 16.50 | 0.0% |
| | Stephens | 4,156 | 4 | 3.96 | 3.96 | 0.0% |
| | Tarrant | 42,517 | 81 | 11.09 | 12.39 | 6.0% |
| | Wise | 636,347 | 411 | 9.75 | 15.58 | 0% |

For certain counties, sufficient data may be available to develop a county-specific emission factor based only on the data available for that particular county. However, a careful examination of these county-specific emission factors (see Attachment C) shows that they vary widely within any one region. This may be indicative of the variation in properties of the condensate produced, or it may be due to an inadequate sample size. Due to the variation observed in the county-specific factors and the uncertainties associated with these factors, the regional emission factors presented in Table 2-15 (see discussion below) are recommended for developing the state-wide area source inventory.

## 2.4 Phone Survey of Area Sources

ERG attempted to contact 54 producers operating in the six regions of interest and request condensate tank emissions data. The companies selected were identified by a search of the RRC website[11] as major producers of condensate in the six regions of interest for the survey. The six regions of interest were the Anadarko, East Texas, Permian, and Western Gulf basins and the Haynesville and Eagle Ford shales. Table 2-9 and Figure 2-2 show the counties within each of the regions that were targeted. These counties were chosen due to their high condensate production relative to all of the counties in that region.[12]

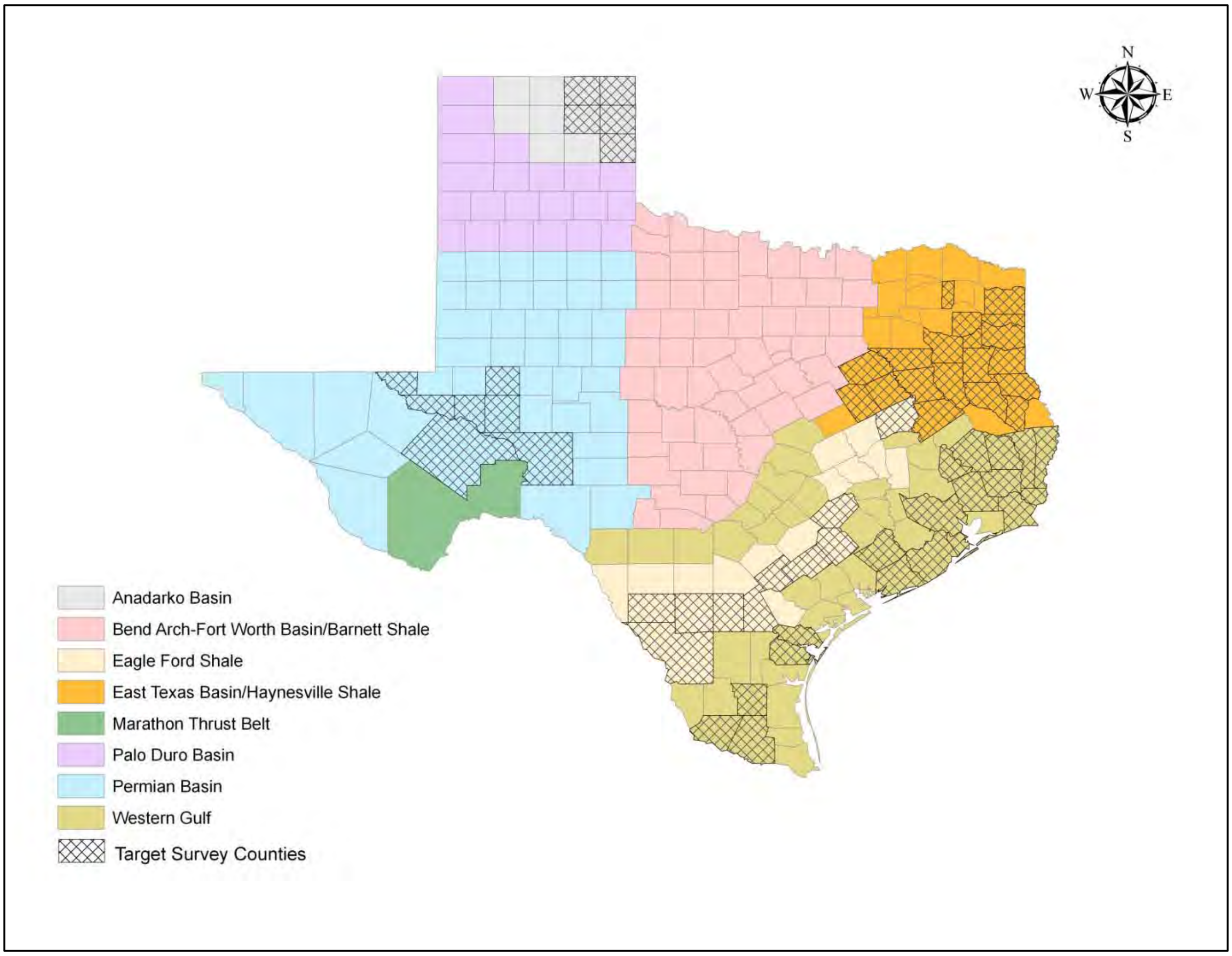
**Table 2-9. Target Survey Counties**

| Anadarko | Permian | East Texas | Western Gulf | Eagle Ford Shale | Haynesville Shale |
|---|---|---|---|---|---|
| Hemphill, Lipscomb, Ochiltree, Roberts, and Wheeler | Crane, Crockett, Loving, Midland, Pecos, Upton, and Ward | Anderson, Cass, Cherokee, Franklin, Freestone, Henderson, Houston, Limestone, Navarro, Smith, and Upshur | Brazoria, Brooks, Galveston, Hardin, Harris, Hidalgo, Jasper, Jefferson, Liberty, Matagorda, Newton, Nueces, Orange, Polk, San Jacinto, San Patricio, Starr, Tyler, and Wharton | DeWitt, Dimmit, Fayette, Karnes, LaSalle, Lavaca, Leon, Live Oak, McMullen, and Webb | Gregg, Harrison, Marion, Nacogdoches, Panola, Rusk, San Augustine, and Shelby |

[11] Railroad Commission of Texas, Statewide Production data Query System, http://www.rrc.state.tx.us/data/online/index.php

[12] Condensate production data at the county level was mapped in ARC GIS, and the top-producing counties in each region were identified. The RRC database was then queried for operators of gas wells in these top-producing counties in each region. Operator production data was compiled for each region and the top producers were identified. These companies were contacted.

**Figure 2-2. Target Survey Counties**




The Bend Arch-Fort Worth basin and Barnett Shale were not surveyed, as adequate data on condensate tank emissions had already been gathered during the Barnett Shale Area Special Inventory.[13] As the survey progressed, it became apparent that much of the condensate produced in the counties designated as Haynesville Shale was actually being produced from another petroleum formation (Cotton Valley Group) located in the same counties as the Haynesville Shale. Therefore, for purposes of calculating emissions, the East Texas and Haynesville Shale regions were merged into one region.

Letters were sent to a total of 61 regional offices at 54 separate companies. Letters were sent to 116 contacts at these companies explaining the survey and requesting cooperation in gathering data. The letter requested data on county, separator pressure, API gravity, 2011 condensate production, 2011 VOC emissions, emissions estimation method, control technology, and control efficiency. This letter is shown in

[13] Texas Commission on Environmental Quality (TCEQ), Barnett Shale Area Special Inventory, Phase Two, http://www.tceq.texas.gov/airquality/point-source-ei/psei.html#barnett2

Attachment A. The initial contact list was obtained from RigData© as it provided the names of people involved in the production (drilling) operation for the respective companies. In most cases, each contact was called 3 or 4 times in order to get a referral to someone in the environmental department of the company. Once phone contact was made with a person in a position to provide the requested information, ERG explained the purpose of the survey and requested participation. ERG obtained email addresses and sent survey materials via email directly to the contact person. The survey materials explained the background and purpose of the survey in greater detail, asked for the voluntary participation of the company, and stated that information would be held confidential. Since many of the companies surveyed only had production in one or two regions, the survey materials were tailored for each company to provide a specific and detailed listing of the region(s) and counties of interest. These materials included a Word document with a table for reporting the data, and an Excel spreadsheet with individual tabs for reporting data from each of the regions. The intent with providing these user-friendly survey materials was to make response as easy as possible and also to gather the data in a format that could be easily copied into spreadsheets for data analysis. These survey materials are shown in Attachment B. Once survey materials had been sent, a follow-up phone call was made a week later to ask if there were any questions and to determine if the company was willing to participate in the survey.

Active survey outreach efforts spanned a six-week period, and included sending the initial contact letters, calling sources to establish contact, sending follow-up letters to the proper contact as needed, making follow-up phone calls, sending emails with survey materials, and making phone calls/sending emails to determine if companies would be willing to participate. Fifteen companies participated in the survey, providing information on more than 251 separate wells/tanks.

### 2.4.1 Analysis of Data Collected via Phone Survey

Fifteen companies responded to the survey, and provided data from more than 251 separate wells/tank batteries. One company sent data for nine representative wells that represented production from 140 separate wells. Other companies sent data for a few sites that were representative of their other wells in that region.

Certain data received in the survey were not used in the analysis. One company provided data for ten wells but no estimates of VOC emissions, and several companies sent data for wells with API gravity less than 40 degrees. Several companies also provided data for wells with a final separator pressure less than 5 psig; this data was not used in the calculations as these low separator pressures are more indicative of wells producing oil and were not consistent with the separator pressures observed in the survey results for the primary condensate producing regions in Texas. Finally, the emissions data generated using non-preferred methods was not included in the analysis.

The raw data collected in the ERG survey, along with notes on which data was excluded from the analysis, is provided in Attachment C.

Data was collected from a sufficient number of tank batteries in each target region. ERG developed a region-wide emission factor for each of the five gas-producing regions targeted in the phone survey. This data was sorted by region. Emission factors were calculated for each of the regions. The survey also requested information on any recovery or control methods used at each well. A very high percentage of respondents indicated that they used recovery or control methods on their wells/tanks. For purposes of comparing the survey results with the test results and emission estimates from earlier studies, emission factors for the emissions before the effect of any controls were calculated.

The producers who responded to this survey used a variety of calculation models (testing, E&P Tank, ProMax, WinSim, VMGSim, HYSYS, GOR, and Vasquez Beggs) for estimating flash emissions. ERG examined these results in light of the evaluation of the accuracy of these models presented in "Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation" (TCEQ, 2009)[14] and TCEQ's guidance on calculating flash emissions[15]. ERG used only records where the flash emissions calculation method was one of the methods preferred by TCEQ. One producer sent test results for three tanks. Since only the results and no underlying data or test reports were submitted, these three data points were treated as being calculated by a preferred method.

Table 2-10 summarizes the findings from the survey. The data show a clear difference in the emission factors by region.

**Table 2-10. Survey Results Using all Valid Survey Data Estimated with Preferred Estimation Methods**

| Region | Total Production Represented in Survey (bbl) | Data Points | Production-Weighted VOC Emission Factor (lbs/bbl) | Arithmetic Average VOC Emission Factor (lbs/bbl) | Percent of Surveyed Production Controlled |
|---|---|---|---|---|---|
| Anadarko | 533,419 | 18 | 1.63 | 7.47 | 99.4% |
| Eagle Ford | 10,538,273 | 41 | 11.3 | 9.41 | 92.2% |

[14] Texas Commission on Environmental Quality, Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation, 2009, http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/20090716-ergi-UpstreamOilGasTankEIModels.pdf

[15] "Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites", APDG 5942, May 2012, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf

**Table 2-10. Survey Results Using all Valid Survey Data Estimated with Preferred Estimation Methods**

| Region | Total Production Represented in Survey (bbl) | Data Points | Production-Weighted VOC Emission Factor (lbs/bbl) | Arithmetic Average VOC Emission Factor (lbs/bbl) | Percent of Surveyed Production Controlled |
|---|---|---|---|---|---|
| East Texas | 518,691 | 83 | 5.91 | 5.75 | 82.1% |
| Permian | 245,545 | 5 | 10.75 | 8.13 | 79.5% |
| Western Gulf | 182,349 | 28 | 1.84 | 5.32 | 46.5% |

### 2.4.2 Use of Vapor Recovery and Controls to Reduce Emissions

The ERG survey data indicates that companies are installing vapor recovery units (VRU) or control devices (flares or combustors) on their highest producing wells. VRUs may be installed for economic reasons as any vapor recovery equipment installed on a high-producing well will deliver a higher return of saleable product per dollar invested in equipment. Similarly, for companies using flares or combustors to control emissions, these control devices are being used on the highest-producing wells.

Survey data indicated that surveyed companies have installed vapor recovery or control devices on 34% of their wells/tanks, representing 91.1% of their total production. The data indicate that the emissions before controls for nearly all of the wells/tanks that had recovery devices or controls installed is greater than 25 tons per year of VOC. Producers reported that emissions from 5.7% of surveyed production were recovered with VRUs, and emissions from 85.4% of surveyed production were controlled with flares or combustors, and the average percent reduction was 97.6%.

This level of control is much higher than the results reported in the 2010 TCEQ study "Control of VOC Flash Emissions from Oil and Condensate Storage Tanks in East Texas", in which survey respondents reported that 72% of surveyed production in the Beaumont-Port Arthur (BPA) counties were controlled, 25% of surveyed production in the HGB area were controlled, and 9% of surveyed production in the Haynesville Shale counties were controlled. The survey data also shows a much higher percentage of control than was observed in the Barnett Shale Area Special Inventory, where 13.2% of total surveyed production was reported as recovered or controlled.[16] This may be due to the differences in production in the Barnett Shale and Haynesville Shale versus the other regions of Texas. The Barnett Shale and Haynesville Shale both produce a 'dry' gas, with limited condensate production. Therefore, it may not have been economically

[16] These data are shown in Table 17 of this report.

feasible or necessary from a regulatory standpoint at the time this survey was taken to control the emissions from the condensate tanks in the Barnett and Haynesville Shale.

The higher level of control observed in the ERG survey may also be due to the increasing awareness and implementation of recovery and control technologies over time, and the effect of new regulations. The Barnett Shale Inventory and the TCEQ surveys were conducted in 2009, whereas the ERG survey was conducted in 2012 and covers production and emissions in 2011. Title 30 Texas Administrative Code 106.352, Permit by Rule for Oil and Gas Handling and Production Facilities[17], became effective on February 2, 2012, which may account for the higher control percentages observed during this survey.

### 2.4.3 Self-Selection Bias

For any survey, the researchers need to consider if the respondents have given them data that is representative of all of their operations. ERG specifically requested in the survey materials and phone conversations that companies submit a random, representative sampling of their wells. ERG has no direct knowledge that any of the companies who responded to this survey biased the data that they submitted. However, the percent of surveyed production with emissions being recovered or controlled (91.1%) is very high when compared to the results obtained from the Barnett Shale Area Special Inventory and other studies. In reviewing the differences in the percentage of production that was reported as recovered or controlled in the ERG survey, versus the amount that was reported as controlled in the Barnett Shale Area Special Inventory, it must be noted that the results of the ERG survey were obtained voluntarily, whereas the Barnett Shale Area Special Inventory was a mandatory survey of all producers operating in that region. ERG collected survey data from 15 large and medium sized companies. A significant portion of the larger companies operate the highest producing wells in many regions. Also, larger companies may have the capital to purchase and install control devices, and may also have more resources to respond to surveys.

### 2.4.4 Innovative Practices that Lower Area Emissions

Two innovative practices in use that have the effect of lowering emissions were identified as part of the survey. During initial phone conversations, two companies declared that they had no tank emissions at upstream sites (well pads) because they no longer routinely used tanks in the field for their day to day operations. While these companies would install a portable liquids tank during the initial phase of well completion, the tank would soon be replaced with piping that collected all gas and condensate from multiple wells in an area and route them to a single gathering station. All gas and liquids would be processed at that station, which utilized vapor recovery and

[17] Texas Commission on Environmental Quality, Rules, http://www.tceq.state.tx.us/rules/indxpdf.html

control equipment such that condensate tank emissions were negligible. This company replaced the traditional tank at the well site with piping and a centralized processing facility.

Another company submitted data with very low emission factors, despite the fact that tank emissions were uncontrolled. When questioned, the company official stated that the emissions factors were low as a result of their operating practices. This company captures as much flash gas as possible and has designed their facilities such that when liquids reach the tanks the pressure has been released to 2 psi [above ambient] allowing flash gas in the liquids to be released prior to the tank, captured by a vapor recovery system, and sent to the gas pipeline. This company also routes the vapors from their storage tanks to a flare. Finally, the emissions from the trucks loading liquids from the field tanks is sent back to the storage tank with vapor balance piping and routed to the flare.

Both of these practices lower the emissions from storage tanks substantially, as they recover or control nearly 100% of the VOC that would normally be emitted in an uncontrolled operation. Ultimately, these potential survey participants did not provide data as part of this survey as they had no upstream tanks and no tank emissions.

## 2.5 Weighting the Data

### 2.5.1 Weighting Data based on Method

This study compiled emissions data produced by both testing and emissions estimation methods, with the data coming from four published studies, one TCEQ inventory, and the survey associated with this report. All of this data was evaluated for its accuracy and relative merit in compiling regional and county-specific emission factors. TCEQ's guidance "Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites"[18] was used as the basis for weighting the data obtained from testing and the various emissions estimation methods. Data obtained from testing is considered the most accurate source of emissions data, and is weighted the highest. Emissions estimates produced through use of process simulation models, E&P TANK, and the Gas-Oil-Ratio method are weighted in decreasing order of preference, consistent with the TCEQ guidance.

Table 2-11 shows the weighting factors applied to each estimation method.

[18] "Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites", APDG 5942, May 2012, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf

**Table 2-11. Weighting Factors by Emissions Estimation Method**

| Emissions Estimation Method | Weight |
|---|---|
| Testing | 4 |
| Process Simulator (HYSIM, HYSIS, VMG, PROMAX) | 2 |
| E&P TANK | 1.5 |
| Gas-Oil-Ratio | 1 |

The equation used to derive the regional emission factors is shown below:

$$\text{Regional Emission Factor (lbs/bbl)}_{\text{Region i}} = [(EF_{\text{Region i TESTING}} \times 4) + (EF_{\text{Region i PROCESS SIMULATOR}} \times 2) + (EF_{\text{Region i E\&P TANK}} \times 1.5) + (EF_{\text{Region i GAS-OIL-RATIO}} \times 1)]/(4+2+1.5+1) \quad \text{(Eq. 2-1)}$$

Where:

$EF_{\text{Region i TESTING}}$ = emission factor for the region based on testing (lbs/bbl)

$EF_{\text{Region i PROCESS SIMULATOR}}$ = emission factor for the region based on process simulator (lbs/bbl)

$EF_{\text{Region i E\&P TANK}}$ = emission factor for the region based on E&P Tank (lbs/bbl)

$EF_{\text{Region i GAS-OIL-RATIO}}$ = emission factor for the region based on the GOR method (lbs/bbl)

### 2.5.2 Weighting Data based on Production

In addition to the method weighting discussed above, a production weighted average was used to assess the average emission rate for the wells/tanks in each particular county or region. This approach more accurately reflects the overall total emissions in a region containing a mix of high and low production sites and is appropriate for area source emissions estimation.

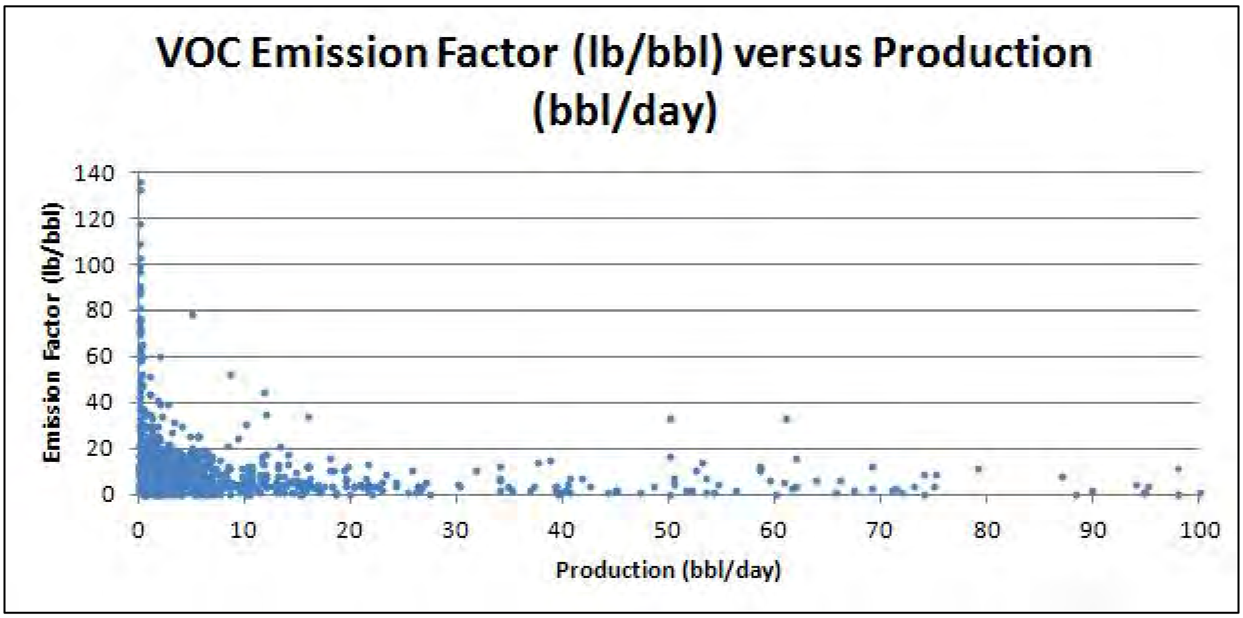
For example, if a region contains ten well sites, and there are 5 sites each producing 2 barrels of condensate per day and having measured emissions of 40 lbs/ bbl, and there are another 5 sites each producing 130 barrels per day and having measured emissions of 4 lbs/bbl, by using a production-weighted approach, the average emissions from these 10 wells/tanks is:

$$(5 \times 2 \times 40 + 5 \times 130 \times 4)/(5 \times 2 + 5 \times 130) = 4.55 \text{ lbs VOC/bbl}$$

The straight arithmetic average for these sites is 22 lbs/bbl. The actual total VOC emissions from the ten sites in this region are 3,000 pounds per day, and the total production from the ten sites in the region is 660 barrels. On a region-wide basis, the actual emissions are 3,000/660 = 4.55 lbs/bbl.

A scatter plot of the data points compiled in this report provides a useful visual depiction of the relationship between emissions on a per barrel basis and production at a given well. Figure 2-3 shows the production for each tank on the x-axis and the VOC emission factor for each tank on the y-axis. The data show a clear relationship between low production and high per-barrel emission factors, yet most of the production in any region comes from the wells with high production, which typically have lower per barrel emission factors.

**Figure 2-3. Relationship between Production and Emission Factor**




## 2.6 Regional Emission Factors

A two-step process was used in compiling the emissions data into regional emission factors for VOC and HAP. First, data was separated into subgroups by region. Subsequently, data records from each regional subgroup were separated into categories by the estimation method used (testing, process simulator, E&P Tank, GOR). A production weighted average emission factor was calculated for each subgroup for each region. The production-weighted average emission factors for each region were then combined into a single regional emission factor using the weighting factors shown in Table 2-11 as described above.

The compiled results of the testing data and estimates from the studies and surveys are shown in the Tables 2-12 through 2-16. Table 2-12 shows the compiled average of emission factors derived from testing. The test results are grouped by region, and a production-weighted average and arithmetic average is calculated for each region. These emission factors show the emissions before the effect of any controls.

### Table 2-12. Average Regional VOC Emission Factors Derived from Testing Data

| Studies | Region | Count of Data Points | Production-Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|---|
| Flash[a] | Anadarko | 4 | 3.89 | 5.22 |
| HARC 51C, Flash[a], Upstream[b] | Fort Worth | 23 | 12.26 | 20.67 |
| Flash[a] | Permian | 8 | 4.39 | 4.34 |
| HARC 51C | Western Gulf | 9 | 16.34 | 13.72 |

[a] Upstream Oil & Gas Storage Tank Project Flash Emissions Models Evaluation (2009).
[b] Upstream Oil & Gas Tank Emissions Measurement (2010).

Table 2-13 shows the compiled emission factors derived from the three studies referenced in this report. These emission factors (all based on E&P TANK, process simulation models, or GOR data) are grouped by region, and a production-weighted average and arithmetic average is calculated for each region. The averages for each region were developed using the weighting factors in Table 2-11. These emission factors show the emissions before the effect of any controls.

### Table 2-13. Average Regional VOC Emission Factors Derived from Estimation Methods

| Studies | Region | Count of Data Points | Production-Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|---|
| Flash[a] | Anadarko | 4 | 14.65 | 16.36 |
| Control of VOC Flash Emissions[b] | East Texas | 21 | 5.78 | 5.78 |
| Upstream[c], Flash[a] | Fort Worth | 10 | 13.69 | 12.89 |
| Flash[a] | Permian | 8 | 23.51 | 18.06 |

[a] Upstream Oil & Gas Storage Tank Project Flash Emissions Models Evaluation (2009).
[b] Control of VOC Flash Emissions from Oil and Condensate Storage Tanks in East Texas (2010).
[c] Upstream Oil & Gas Tank Emissions Measurement (2010).

Table 2-14 shows the compiled average emission factors derived from the ERG 2012 survey responses and the 2009 Barnett Shale Special Area Inventory. In these surveys, producers used direct measurement and estimation methods (E&P TANK, process simulation models, GOR) to estimate emissions from their condensate tanks. However, for the testing data, only the test results and no underlying data or test reports were submitted. Therefore, the testing data were treated as being calculated by a preferred method and given a weight of 1.5 instead of 4.

These emission estimates are grouped by region, and a production-weighted average and arithmetic average is calculated for each region. The averages for each region were weighted according to the weighting factors in Table 2-11. These emission factors show the emissions before the effect of any controls.

**Table 2-14. Average Regional VOC Emission Factors from ERG Survey Data and Barnett Shale Inventory Data**

| Survey | Region | Count of Data Points | Production-Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|---|
| ERG 2012 survey | Anadarko | 18 | 2.49 | 6.45 |
| ERG 2012 survey | Eagle Ford | 41 | 10.5 | 10.0 |
| ERG 2012 survey | East Texas | 83 | 3.51 | 6.22 |
| ERG 2012 survey | Permian | 5 | 6.25 | 6.08 |
| ERG 2012 survey | Western Gulf | 28 | 4.95 | 16.1 |
| Barnett Shale Inventory | Fort Worth | 1,575 | 7.54 | 12.2 |

Table 2-15 shows the compiled average emission factors when the data from the testing results (Table 2-12), studies (Table 2-13), and the ERG 2012 and Barnett Shale surveys (Table 2-14) is combined. The testing and emission estimate data is grouped by region, and a production-weighted average and an arithmetic average is determined for each region. The production-weighted average and arithmetic average for each region were weighted according to the weighting factors in Table 2-11. As there are no data available for the Palo Duro Basin and the Marathon Thrust Belt, a statewide average is used for these two regions. These emission factors show the emissions before the effect of any controls.

**Table 2-15. Average Regional VOC Emission Factors**

| Region | Count of Data Points | Production-Weighted Emission Factor (lb/bbl) | Arithmetic Average Emission Factor (lb/bbl) |
|---|---|---|---|
| Anadarko | 26 | 3.15 | 5.87 |
| Eagle Ford Shale | 41 | 10.5 | 10.0 |
| East Texas/Haynesville Shale | 104 | 4.22 | 5.92 |
| Fort Worth/Barnett Shale | 1,604 | 9.76 | 16.0 |
| Permian | 21 | 7.07 | 5.90 |

## Table 2-15. Average Regional VOC Emission Factors

| Region | Count of Data Points | Production-Weighted Emission Factor (lb/bbl) | Arithmetic Average Emission Factor (lb/bbl) |
|---|---|---|---|
| Western Gulf | 37 | 11.0 | 14.8 |
| Palo Duro[a] | N/A | 7.61 | 9.75 |
| Marathon Thrust Belt[a] | N/A | 7.61 | 9.75 |

[a] Statewide average.

Figure 2-4 provides the geographical distribution of the data sources used to compile the regional emission factors in Table 2-15 on a county-basis.

**Figure 2-4. Condensate Tank Emission Data Sources by County**

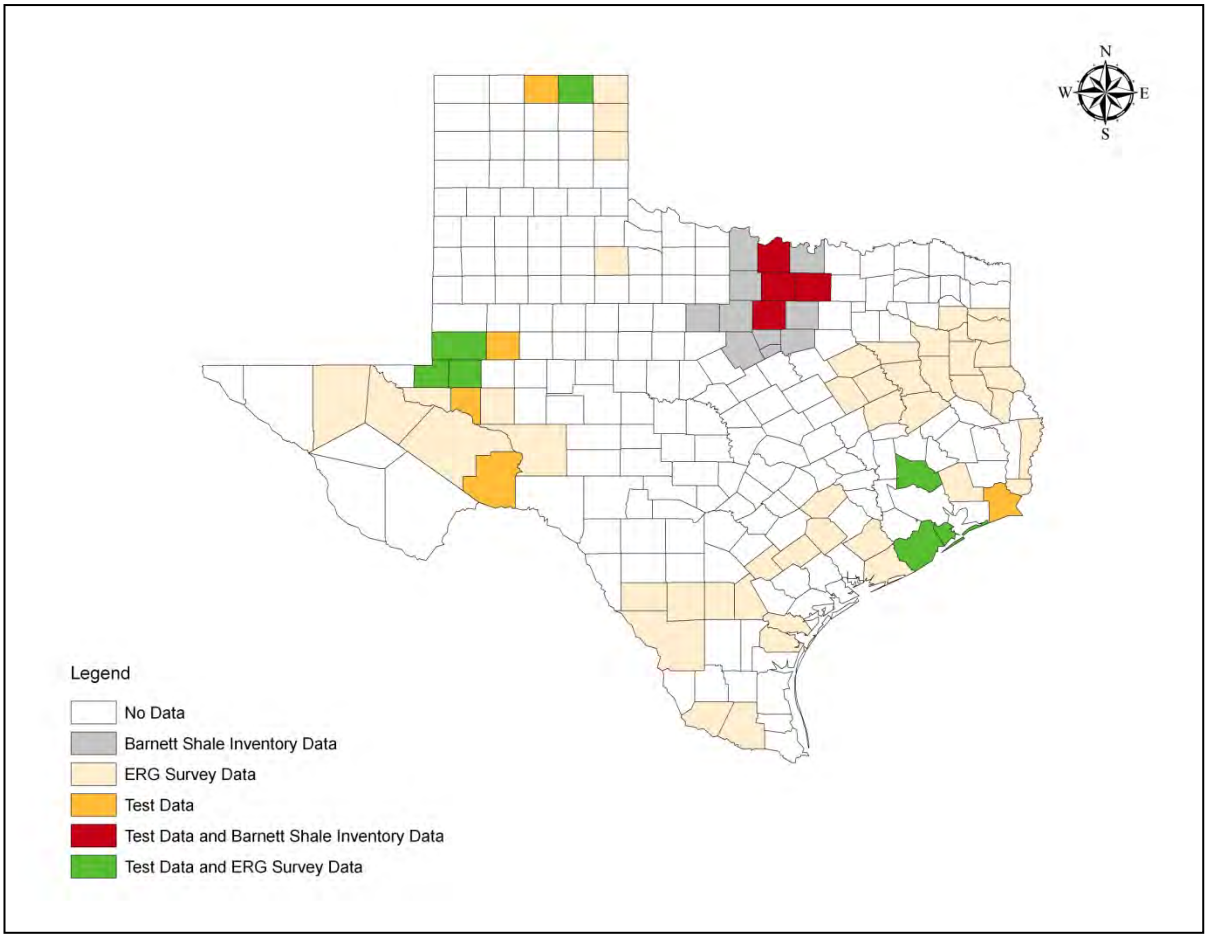
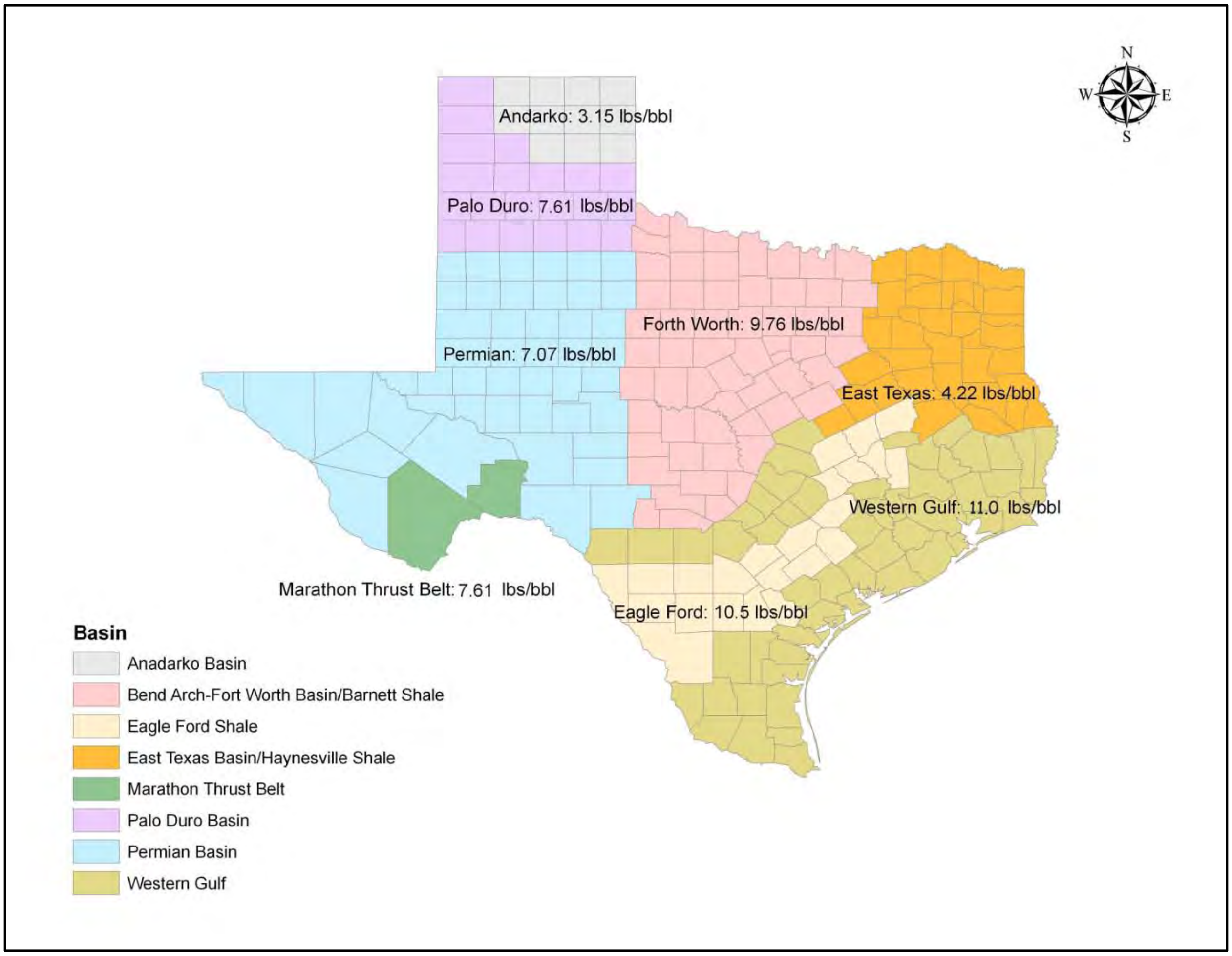


Figure 2-5 shows the results from Table 2-15 geographically. Determination of which counties are included in each region is from the United States Geological Survey.[19] Counties in the Eagle Ford Shale were identified by the RRC.[20] For certain counties, there was sufficient data available to develop a county-specific emission factor based only on the data available for that particular county. However, a careful examination of these county-specific emission factors (see Attachment C) shows that they vary widely within any one region. This may be indicative of the variation in properties of the condensate produced, or it may be due to an inadequate sample size. Due to the variation observed in the county-specific factors and the uncertainties associated with these factors, the regional emission factors presented in Table 2-15 are recommended for developing the state-wide area source inventory.

**Figure 2-5. Average Regional Emission Factors, Before Controls**




[19] United States Geological Survey, National Oil and Gas Assessment, http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment.aspx
[20] Texas Railroad Commission, Eagle Ford Information, http://www.rrc.state.tx.us/eagleford/

The region-specific condensate tank emission factors can then be assigned on a county basis by allocating each county in the state to one of the regions identified in Table 2-15. The county-level VOC emission factor (both production weighted and arithmetic average) for each county in Texas is shown in Table 2-16.

### Table 2-16. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Anderson | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Andrews | Permian | 7.07 | 5.90 |
| Angelina | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Aransas | Western Gulf | 11.0 | 14.8 |
| Archer | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Armstrong | Palo Duro | 7.61 | 9.75 |
| Atascosa | Eagle Ford Shale | 10.5 | 10.0 |
| Austin | Western Gulf | 11.0 | 14.8 |
| Bailey | Palo Duro | 7.61 | 9.75 |
| Bandera | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Bastrop | Western Gulf | 11.0 | 14.8 |
| Baylor | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Bee | Eagle Ford Shale | 10.5 | 10.0 |
| Bell | Western Gulf | 11.0 | 14.8 |
| Bexar | Western Gulf | 11.0 | 14.8 |
| Blanco | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Borden | Permian | 7.07 | 5.90 |
| Bosque | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Bowie | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Brazoria | Western Gulf | 11.0 | 14.8 |
| Brazos | Eagle Ford Shale | 10.5 | 10.0 |
| Brewster | Marathon Thrust Belt | 7.61 | 9.75 |
| Briscoe | Palo Duro | 7.61 | 9.75 |
| Brooks | Western Gulf | 11.0 | 14.8 |
| Brown | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Burleson | Eagle Ford Shale | 10.5 | 10.0 |
| Burnet | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Caldwell | Western Gulf | 11.0 | 14.8 |
| Calhoun | Western Gulf | 11.0 | 14.8 |
| Callahan | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cameron | Western Gulf | 11.0 | 14.8 |
| Camp | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Carson | Anadarko | 3.15 | 5.87 |
| Cass | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Castro | Palo Duro | 7.61 | 9.75 |
| Chambers | Western Gulf | 11.0 | 14.8 |
| Cherokee | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Childress | Palo Duro | 7.61 | 9.75 |
| Clay | Fort Worth/Barnett Shale | 9.76 | 16.0 |

## Table 2-16. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Cochran | Permian | 7.07 | 5.90 |
| Coke | Permian | 7.07 | 5.90 |
| Coleman | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Collin | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Collingsworth | Palo Duro | 7.61 | 9.75 |
| Colorado | Western Gulf | 11.0 | 14.8 |
| Comal | Western Gulf | 11.0 | 14.8 |
| Comanche | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Concho | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cooke | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Coryell | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Cottle | Palo Duro | 7.61 | 9.75 |
| Crane | Permian | 7.07 | 5.90 |
| Crockett | Permian | 7.07 | 5.90 |
| Crosby | Permian | 7.07 | 5.90 |
| Culberson | Permian | 7.07 | 5.90 |
| Dallam | Palo Duro | 7.61 | 9.75 |
| Dallas | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Dawson | Permian | 7.07 | 5.90 |
| Deaf Smith | Palo Duro | 7.61 | 9.75 |
| Delta | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Denton | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| DeWitt | Eagle Ford Shale | 10.5 | 10.0 |
| Dickens | Permian | 7.07 | 5.90 |
| Dimmit | Eagle Ford Shale | 10.5 | 10.0 |
| Donley | Palo Duro | 7.61 | 9.75 |
| Duval | Western Gulf | 11.0 | 14.8 |
| Eastland | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Ector | Permian | 7.07 | 5.90 |
| Edwards | Permian | 7.07 | 5.90 |
| El Paso | Permian | 7.07 | 5.90 |
| Ellis | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Erath | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Falls | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Fannin | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Fayette | Eagle Ford Shale | 10.5 | 10.0 |
| Fisher | Permian | 7.07 | 5.90 |
| Floyd | Palo Duro | 7.61 | 9.75 |
| Foard | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Fort Bend | Western Gulf | 11.0 | 14.8 |
| Franklin | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Freestone | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Frio | Eagle Ford Shale | 10.5 | 10.0 |
| Gaines | Permian | 7.07 | 5.90 |

## Table 2-16. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Galveston | Western Gulf | 11.0 | 14.8 |
| Garza | Permian | 7.07 | 5.90 |
| Gillespie | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Glasscock | Permian | 7.07 | 5.90 |
| Goliad | Western Gulf | 11.0 | 14.8 |
| Gonzales | Eagle Ford Shale | 10.5 | 10.0 |
| Gray | Anadarko | 3.15 | 5.87 |
| Grayson | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Gregg | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Grimes | Eagle Ford Shale | 10.5 | 10.0 |
| Guadalupe | Western Gulf | 11.0 | 14.8 |
| Hale | Palo Duro | 7.61 | 9.75 |
| Hall | Palo Duro | 7.61 | 9.75 |
| Hamilton | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hansford | Anadarko | 3.15 | 5.87 |
| Hardeman | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hardin | Western Gulf | 11.0 | 14.8 |
| Harris | Western Gulf | 11.0 | 14.8 |
| Harrison | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Hartley | Palo Duro | 7.61 | 9.75 |
| Haskell | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hays | Western Gulf | 11.0 | 14.8 |
| Hemphill | Anadarko | 3.15 | 5.87 |
| Henderson | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Hidalgo | Western Gulf | 11.0 | 14.8 |
| Hill | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hockley | Permian | 7.07 | 5.90 |
| Hood | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Hopkins | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Houston | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Howard | Permian | 7.07 | 5.90 |
| Hudspeth | Permian | 7.07 | 5.90 |
| Hunt | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Hutchinson | Anadarko | 3.15 | 5.87 |
| Irion | Permian | 7.07 | 5.90 |
| Jack | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Jackson | Western Gulf | 11.0 | 14.8 |
| Jasper | Western Gulf | 11.0 | 14.8 |
| Jeff Davis | Permian | 7.07 | 5.90 |
| Jefferson | Western Gulf | 11.0 | 14.8 |
| Jim Hogg | Western Gulf | 11.0 | 14.8 |
| Jim Wells | Western Gulf | 11.0 | 14.8 |
| Johnson | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Jones | Fort Worth/Barnett Shale | 9.76 | 16.0 |

## Table 2-16. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Karnes | Eagle Ford Shale | 10.5 | 10.0 |
| Kaufman | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Kendall | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Kenedy | Western Gulf | 11.0 | 14.8 |
| Kent | Permian | 7.07 | 5.90 |
| Kerr | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Kimble | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| King | Permian | 7.07 | 5.90 |
| Kinney | Western Gulf | 11.0 | 14.8 |
| Kleberg | Western Gulf | 11.0 | 14.8 |
| Knox | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| La Salle | Eagle Ford Shale | 10.5 | 10.0 |
| Lamar | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Lamb | Palo Duro | 7.61 | 9.75 |
| Lampasas | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Lavaca | Eagle Ford Shale | 10.5 | 10.0 |
| Lee | Eagle Ford Shale | 10.5 | 10.0 |
| Leon | Eagle Ford Shale | 10.5 | 10.0 |
| Liberty | Western Gulf | 11.0 | 14.8 |
| Limestone | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Lipscomb | Anadarko | 3.15 | 5.87 |
| Live Oak | Eagle Ford Shale | 10.5 | 10.0 |
| Llano | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Loving | Permian | 7.07 | 5.90 |
| Lubbock | Permian | 7.07 | 5.90 |
| Lynn | Permian | 7.07 | 5.90 |
| Madison | Western Gulf | 11.0 | 14.8 |
| Marion | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Martin | Permian | 7.07 | 5.90 |
| Mason | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Matagorda | Western Gulf | 11.0 | 14.8 |
| Maverick | Eagle Ford Shale | 10.5 | 10.0 |
| McCulloch | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| McLennan | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| McMullen | Eagle Ford Shale | 10.5 | 10.0 |
| Medina | Western Gulf | 11.0 | 14.8 |
| Menard | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Midland | Permian | 7.07 | 5.90 |
| Milam | Eagle Ford Shale | 10.5 | 10.0 |
| Mills | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Mitchell | Permian | 7.07 | 5.90 |
| Montague | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Montgomery | Western Gulf | 11.0 | 14.8 |
| Moore | Anadarko | 3.15 | 5.87 |

## Table 2-16. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Morris | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Motley | Palo Duro | 7.61 | 9.75 |
| Nacogdoches | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Navarro | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Newton | Western Gulf | 11.0 | 14.8 |
| Nolan | Permian | 7.07 | 5.90 |
| Nueces | Western Gulf | 11.0 | 14.8 |
| Ochiltree | Anadarko | 3.15 | 5.87 |
| Oldham | Palo Duro | 7.61 | 9.75 |
| Orange | Western Gulf | 11.0 | 14.8 |
| Palo Pinto | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Panola | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Parker | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Parmer | Palo Duro | 7.61 | 9.75 |
| Pecos | Permian | 7.07 | 5.90 |
| Polk | Western Gulf | 11.0 | 14.8 |
| Potter | Palo Duro | 7.61 | 9.75 |
| Presidio | Permian | 7.07 | 5.90 |
| Rains | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Randall | Palo Duro | 7.61 | 9.75 |
| Reagan | Permian | 7.07 | 5.90 |
| Real | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Red River | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Reeves | Permian | 7.07 | 5.90 |
| Refugio | Western Gulf | 11.0 | 14.8 |
| Roberts | Anadarko | 3.15 | 5.87 |
| Robertson | Eagle Ford Shale | 10.5 | 10.0 |
| Rockwall | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Runnels | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Rusk | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Sabine | East Texas/Haynesville Shale | 4.22 | 5.92 |
| San Augustine | East Texas/Haynesville Shale | 4.22 | 5.92 |
| San Jacinto | Western Gulf | 11.0 | 14.8 |
| San Patricio | Western Gulf | 11.0 | 14.8 |
| San Saba | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Schleicher | Permian | 7.07 | 5.90 |
| Scurry | Permian | 7.07 | 5.90 |
| Shackelford | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Shelby | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Sherman | Anadarko | 3.15 | 5.87 |
| Smith | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Somervell | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Starr | Western Gulf | 11.0 | 14.8 |
| Stephens | Fort Worth/Barnett Shale | 9.76 | 16.0 |

## Table 2-16. County-Level VOC Emission Factors

| County | Region | Production Weighted Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|
| Sterling | Permian | 7.07 | 5.90 |
| Stonewall | Permian | 7.07 | 5.90 |
| Sutton | Permian | 7.07 | 5.90 |
| Swisher | Palo Duro | 7.61 | 9.75 |
| Tarrant | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Taylor | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Terrell | Marathon Thrust Belt | 7.61 | 9.75 |
| Terry | Permian | 7.07 | 5.90 |
| Throckmorton | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Titus | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Tom Green | Permian | 7.07 | 5.90 |
| Travis | Western Gulf | 11.0 | 14.8 |
| Trinity | Western Gulf | 11.0 | 14.8 |
| Tyler | Western Gulf | 11.0 | 14.8 |
| Upshur | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Upton | Permian | 7.07 | 5.90 |
| Uvalde | Western Gulf | 11.0 | 14.8 |
| Val Verde | Permian | 7.07 | 5.90 |
| Van Zandt | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Victoria | Western Gulf | 11.0 | 14.8 |
| Walker | Western Gulf | 11.0 | 14.8 |
| Waller | Western Gulf | 11.0 | 14.8 |
| Ward | Permian | 7.07 | 5.90 |
| Washington | Western Gulf | 11.0 | 14.8 |
| Webb | Eagle Ford Shale | 10.5 | 10.0 |
| Wharton | Western Gulf | 11.0 | 14.8 |
| Wheeler | Anadarko | 3.15 | 5.87 |
| Wichita | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Wilbarger | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Willacy | Western Gulf | 11.0 | 14.8 |
| Williamson | Western Gulf | 11.0 | 14.8 |
| Wilson | Eagle Ford Shale | 10.5 | 10.0 |
| Winkler | Permian | 7.07 | 5.90 |
| Wise | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Wood | East Texas/Haynesville Shale | 4.22 | 5.92 |
| Yoakum | Permian | 7.07 | 5.90 |
| Young | Fort Worth/Barnett Shale | 9.76 | 16.0 |
| Zapata | Western Gulf | 11.0 | 14.8 |
| Zavala | Eagle Ford Shale | 10.5 | 10.0 |

## 2.7 Accounting for the Effect of Recovery and Control Devices

The effect of existing vapor recovery and control devices should be accounted for in determining emissions from area sources. However, there is limited information on the use of control devices in the condensate producing regions of Texas, and the quantity of the information varies.

### 2.7.1 Barnett Shale

The TCEQ Barnett Shale Special Inventory data indicates whether condensate tank emissions are recovered or controlled at each site. This dataset contains 1,575 records covering the 14 counties listed in Table 2-8 above. The Barnett Shale Inventory data indicate that 13.2% of total surveyed production in these 14 counties was controlled, and the average percent reduction was 97.2%. The 2009 RRC condensate production data for these 14 counties is 2,680,019 bbl. The surveyed production (2,479,409 bbl from Table 2-8) represents 92.5% of total 2009 condensate production in these counties. Because the Barnett Shale Inventory was a mandatory survey of all producers in these counties, and had a very high response rate, we can assume that 12.2% (92.5% x 13.2%) of total production in that region should be considered to be controlled by 97.2%, for an overall reduction of 11.8%.

### 2.7.2 HGB, BPA, and Haynesville Shale

The 2010 study conducted by ENVIRON for TCEQ titled "*Control of VOC Flash Emissions from Oil and Condensate Storage Tanks in East Texas*" reported on control of emissions from oil and condensate storage tanks in three geographic regions of Texas. This study investigated the effect on VOC emissions reductions in the HGB nonattainment area due to the implementation of requirements in Title 30 Texas Administrative Code 115.112(d)(5). The report investigated the possible effects should this same rule be implemented in the BPA area and the Haynesville Shale area. This report also considered the effect of the Texas Permit by Rule (Title 30 TAC 106.352) requirements, which allow a well/tank site with emissions less than 25 tons of VOC per year to qualify for a more streamlined permit. [21]

This report included results from surveys of the HGB area, the BPA area, the Haynesville Shale, and a TCEQ Region 12 survey for the HGB area. 82 producers responded to these two surveys and submitted control information for 1,940 sites.[22]

[21] The Permit By Rule for Oil and Gas sites (Title 30 TAC 106.352) allows new or modified facilities that meet certain conditions and that emit less than 25 tons per year of VOC to be obtain authorization per rule requirements. It has the effect of encouraging larger oil and gas sources to install control devices on their oil and condensate tanks so as to limit emissions.

[22] There is a small overlap in data collected for the HGB area (Table ES-3 of the report). It does not affect the results, as the overlap has been accounted for in analyzing the data.

The data collected for this report[23] indicated that 25% of the surveyed production in the HGB area was controlled, 9% of the surveyed production in the Haynesville Shale area was controlled, and 72% of the surveyed production in the BPA area was controlled. The high surveyed percentage of controlled production in the BPA area can be attributed to a group of large condensate producing sites (accounting for more than 1000 bbl/day) equipped with a suite of control devices. These sites accounted for approximately half of the surveyed BPA area production and significantly contribute to the high percentage of surveyed controlled production.

This study also requested information from producers about tank emissions controls. When this information is combined with production information, it gives an estimate of the percent of total surveyed production in each of the surveyed areas that is controlled.

### 2.7.3 Calculation of Control Factor

Each region-specific or county-specific control factor should reflect the percentage of production in that region/county that was reported as controlled per the survey. For the percentage of production that was not reported in these surveys, instead of assuming this production is uncontrolled, a default control percentage is applied. The assumed default control factor for the production not reported in these surveys was developed from the TCEQ Barnett Shale Special Inventory data. The large sample size of this special inventory data combined with the characteristics of the Barnett Shale formation represents a conservative control estimate.

To calculate an overall control factor, a multi-step calculation was developed that accounts for reported versus unreported survey condensate production. This calculation is outlined for the HGB area in detail below; the same calculation was employed with area-specific data for the other areas. The calculation methodology was as follows:

1. 68 % of HGB condensate production was reported in the survey.
    a. 25% of reported production is controlled at a 95% level
    b. 75% of reported production is not controlled
2. 32 % of HGB production data was not reported in the survey
3. To account for the different categories of data, each category will be treated separately and the results summed to produce the control factor.
    a. For the controlled category, category 1a, the basic formula is:
        i. Portion of control factor = (percent of production represented by category) * (percent of controlled production) * (control efficiency)
        ii. For category 1a, this equals: (0.680*0.25*0.95) = 0.161 or 16.1%
    b. For the category where production was not reported, category 2, default data is assumed and the basic formula is:

[23] TCEQ provided ERG with three spreadsheets containing the survey data obtained from the ENVIRON surveys.

    i. Portion of control factor = (percent of production represented by category) * (percent of controlled production, default from Barnett Shale special inventory) * (control efficiency, default from Barnett Shale special inventory)
    ii. For category 2, this equals: (0.320*0.122*0.972) = 0.0379 or 3.8%
  c. Total control for 100% of production in the HGB area is therefore the sum of portion of controls from categories 1a and 2, or (16.1+3.8) % or 19.9%.

Table 2-17 below presents the findings of this analysis and includes a recommended control factor for each region.

### 2.7.4 ERG 2012 Survey

The ERG 2012 survey collected data from 15 companies for 251 sites in 50 counties. Data from 175 of these sites was used in calculating results. The survey data show that emissions from 91.1% of all surveyed production was either recovered with a VRU or controlled with a flare or combustor, and the average percent reduction was 97.6%. These are exceptionally high percentages when compared with the amount of production reported as controlled in the Barnett Shale Inventory and the TCEQ 2010 study above. The ERG 2012 survey data was voluntary, and may not be representative of all producers or other counties in the regions surveyed. This difference may also be due to the characteristics of the Barnett Shale and Haynesville Shale formations versus the other regions of Texas. The Barnett Shale and Haynesville Shale both produce a 'dry' gas, with little condensate production. Therefore, it may not have been economical or necessary from a regulatory standpoint at the time this survey was taken to control the emissions from the condensate tanks in the Barnett and Haynesville Shale.

The higher level of control observed in the ERG survey may also be due to the increasing implementation of recovery and control technologies over time, and the effect of new regulations limiting air pollutant emissions in specific areas. The Barnett Shale Inventory and the TCEQ surveys were conducted in 2009, whereas the ERG survey was conducted in 2012 and covers production and emissions in 2011. Title 30 Texas Administrative Code 106.352, Permit by Rule for Oil and Gas Handling and Production Facilities[24], became effective on February 2, 2012, which may account for the higher control percentages observed during this survey.

[24] Texas Commission on Environmental Quality, Rules, http://www.tceq.state.tx.us/rules/indxpdf.html

## Table 2-17. Percentage of Surveyed Production with Tank Emissions Controlled in the HGB, BPA, and Haynesville Shale Areas

| Region (counties) | 2009 Total Production Reported to RRC [a] (bbl) | Number of Sites/Tank Batteries Surveyed [b] | Total Surveyed Production [c] | Total Controlled Production Reported in Survey [d] (bbl) | Percent of Reported Production That is Controlled [d] (%) | Percent of Production Not Reported in the Survey [e] (%) | Control Efficiency (%) | Control Factor (%) |
|---|---|---|---|---|---|---|---|---|
| **Houston-Galveston-Brazoria** (Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, Waller) | 3,436,859 | 180 | 2,335,837 | 583,462 | 25.0 | 32.0 | 95 | 19.9 |
| **Beaumont - Port Arthur** (Hardin, Jefferson, Orange) | 5,456,431 | 26 | 1,196,723 | 863,250 | 72.1 | 78.1 | 90 | 23.5 |
| **Haynesville Shale** (Gregg, Harrison, Marion, Nacogdoches, Panola, Rusk, San Augustine, Smith, Shelby, Upshur) | 5,445,378 | 523 | 2,018,527 | 182,525 | 9.04 | 62.9 | 90 | 10.5 |
| **Barnett Shale** (Clay, Cooke, Denton, Erath, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Stephens, Tarrant, Wise) [f] | 2,680,019 | 1,575 | 2,478,858 | 326,545 | 13.2 | 7.5 | 97.2 | 11.8 |

[a] Data for 2009 condensate production from these counties is from a production data query at the Railroad Commission of Texas website.
[b] Data for the number of sites/tank batteries surveyed in the HGB, BPA, and Haynesville Shale areas comes from Tables 14a and 14b of the "*Control of VOC Flash Emissions from Oil and Condensate Storage Tanks in East Texas*" (TCEQ, 2010) report.
[c] Data for the total surveyed production for the HGB, BPA, and Haynesville Shale areas comes from Table 8 of the "*Control of VOC Flash Emissions from Oil and Condensate Storage Tanks in East Texas*" report.
[d] Data for the total controlled production for the HGB, BPA, and Haynesville Shale areas comes from spreadsheets provided to ERG by TCEQ.
[e] This percentage is derived from the 2009 total production reported to RRC (column 2) and the total surveyed production (column 4).
[f] The data for the Barnett Shale counties comes from the TCEQ Barnett Shale Special Inventory (Table 2-8 and Attachment C of this report).

In assessing whether the surveyed data is representative of all basin operations, ERG has no direct knowledge that any of the companies who responded to this survey biased the data that they submitted. However, as noted above, the percent of surveyed production with emissions being recovered or controlled (91.1%) is very high when compared to the results obtained from the Barnett Shale Area Special Inventory and other studies. ERG collected survey data from 15 large and medium sized companies. A significant portion of the larger companies operate the highest producing wells in many regions. Also, larger companies may have the capital to purchase and install control devices, and may also have more resources to respond to surveys.

The figures for surveyed production as a percentage of total production reported by the RRC also indicate that the survey counts as 'condensate' a significant percentage of liquids production that the RRC considers to be oil. Although ERG requested data for condensate production, data was also requested for wells producing liquids with an API gravity greater than 40 degrees. Since the RRC condensate production values are ultimately used for TCEQ area source emissions inventory development, survey data was reviewed and outlier data suspected of representing oil production (e.g., extremely low separator pressure) was not used for emissions and control factor development. The majority of outlier data appeared in the Permian Basin region, where oil production is at least 100 times greater than condensate production.[25] Survey responses for certain basins in the state captured a limited amount of basin production. With the varying amount of data available for analysis, uncertainties exist about applying the control factor from the surveyed data to the remainder of condensate production in those counties and areas.

Table 2-18 shows the control information developed from the ERG survey data.

## 2.8 Summary of Findings and Recommended Emission Factors

Analysis of data from four studies and two surveys indicates that there exists a distinct regional variation in emissions from condensate storage tanks across the oil and gas producing regions of Texas. Emission estimates from testing and software models were considered and each of these data sources has limitations.

Survey data indicate that producers are installing recovery and control devices on an increasing percentage of their condensate wells. The Barnett Shale Inventory data indicates that emissions from 12.2% of total surveyed production were controlled, and data from the 15 producers participating in the ERG 2012 survey indicated that emissions from 91.0% of their total production was recovered or controlled. Other innovative techniques, such as piping all production directly to a centralized processing facility, or using multi-stage separators with ultra-low final stage pressure drop, also

[25] Railroad Commission of Texas, http://www.rrc.state.tx.us/permianbasin/index.php

reduce emissions from condensate production at area sources. An accurate assessment of area source emissions will need to account for the effect of these techniques, and for any increase in their implementation over time.

ERG recommends use of the uncontrolled, production-weighted VOC emission factors in Table 2-16 when calculating the emissions from area source condensate production. Application of the control factors to the percentage of surveyed, controlled condensate production presented in Table 2-17 is recommended for the HGB, BPA, Haynesville Shale, and Barnett Shale counties listed. Despite the availability of ERG 2012 survey data for other regions as shown in Table 2-18, the 11.8% control factor derived from the comprehensive Barnett Shale Inventory is recommended for the remainder of condensate production in these regions and throughout the state until additional data for a large number of producers in the other regions can be obtained. These emission reduction factors will capture the effect of emission recovery and control devices that producers have installed on their production equipment in the counties listed, while conservatively estimating emissions for the remainder of condensate production.

Alternatively, the control factors presented in both Tables 2-17 and 2-18 can be applied to the percentage of surveyed, controlled condensate production for the counties in each region. For the remainder of production, application of the 11.8% control factor derived from the Barnett Shale Inventory is recommended.

## Table 2-18. Surveyed Production, Total Production, Percent of Surveyed Production Controlled, and Control Factor, by Region

| Region | Total Production Represented in Survey (bbl) | Total Annual Production[a] (bbl) | Percent of 2011 Production Represented by the Survey | Total Controlled Production Reported in Survey (bbl) | Percent of Surveyed Production Controlled | Control Efficiency (%) | Control Factor (%)[b] | Alternate Control Factor (%)[c] |
|---|---|---|---|---|---|---|---|---|
| Anadarko | 533,419 | 8,609,960 | 6.2 | 530,324 | 99.4 | 97.9 | 6.03 | 17.1 |
| Eagle Ford | 10,538,273 | 24,343,253 | 43.3 | 9,716,987 | 92.2 | 98.5 | 39.3 | 46.0 |
| East Texas | 518,691 | 4,681,732 | 11.1 | 425,644 | 82.1 | 98.1 | 8.92 | 19.4 |
| Permian | 245,545 | 2,036,996 | 12.1 | 195,275 | 79.5 | 94.7 | 9.08 | 19.5 |
| Western Gulf | 182,349 | 18,241,171 | 1.0 | 84,785 | 46.5 | 98.0 | 0.46 | 12.2 |

[a] Data for 2009 condensate production from the Barnett Shale area and 2011 condensate production for the other five regions is from the RRC.
[b] Control factor assumes that only the surveyed production is controlled.
[c] Control factor assumes that surveyed production is controlled at the surveyed control rate, and that the unsurveyed production is controlled at a default rate of 11.8 percent.

# 3.0 Hazardous Air Pollutant Emissions from Condensate Storage Tanks

As part of the study to refine the condensate tank VOC emission factor used in the TCEQ area source inventory, ERG accumulated a significant amount of data on emissions of benzene, toluene, ethylbenzene, and xylene (BTEX) from condensate storage tanks. This data was obtained from the 2006 HARC study, the Barnett Shale Area Special Inventory Phase II survey of producers, and E&P TANK report data submitted by producers in response to the ERG 2012 survey. ERG determined that the amount and quality of this data was sufficient to allow development of region-specific emission factors for BTEX emissions from storage tanks for four geographic regions in the state. These four regions are: Eagle Ford Shale, East Texas/Haynesville Shale, Bend Arch-Fort Worth/Barnett Shale, and Western Gulf. These regions are shown in Figure 2-1 above.

## 3.1 BTEX Emissions Data Derived from Testing

The researchers who conducted the study *"VOC Emissions from Oil and Condensate Storage Tanks"* (Houston Advanced Research Center, 2006, and Texas Environmental Research Consortium, 2009)[26] also made measurements of BTEX content of the emissions from each of the oil and condensate storage tanks. The report provided data for the weight percent of benzene, toluene, ethylbenzene, and xylene in the tank vent gas; data on the weight percent of VOC in the tank vent gas; the liquid production in barrels per day; and the VOC emissions in pounds per day and pounds per barrel. ERG re-examined the data from the sites examined in the HARC 2006 study. Although 27 sites produce liquids having an API gravity of 40 degrees or greater, only data from the 22 sites designated as being condensate is considered. In this analysis, three data points were removed from the data set as was done for the VOC emission factor development process as described above. An emission factor for each of the remaining 19 sites was calculated. Table 2-1 (above) and Table 3-1 (below) show the measurement data from the HARC 2006 study for these 19 condensate tanks.

**Table 3-1. VOC and BTEX Content in the Vent Gas**

| Tank Battery | Weight % VOC | Weight % Benzene | Weight % Toluene | Weight % Ethylbenzene | Weight % Xylene |
|---|---|---|---|---|---|
| 2 | 47 | 0.34 | 0.53 | 0.04 | 0.21 |
| 3 | 62 | 0.63 | 1.10 | 0.06 | 0.46 |
| 4 | 57 | 0.57 | 1.02 | 0.06 | 0.41 |
| 5 | 70 | 0.75 | 1.32 | 0.07 | 0.55 |
| 6 | 65 | 0.49 | 0.56 | 0.03 | 0.14 |
| 13 | 81 | 0.19 | 0.40 | 0.01 | 0.14 |
| 14 | 53 | 0.13 | 0.33 | 0.02 | 0.16 |

[26] Houston Advanced Research Center, VOC Emissions from Oil and Condensate Storage Tanks, October 31, 2006. http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf

## Table 3-1. VOC and BTEX Content in the Vent Gas

| Tank Battery | Weight % VOC | Weight % Benzene | Weight % Toluene | Weight % Ethylbenzene | Weight % Xylene |
|---|---|---|---|---|---|
| 15 | 82 | 0.18 | 0.25 | 0.01 | 0.09 |
| 16 | 85 | 0.20 | 0.41 | 0.02 | 0.19 |
| 18 | 70 | 0.23 | 0.65 | 0.03 | 0.38 |
| 19 | 77 | 0.25 | 0.58 | 0.02 | 0.25 |
| 20 | 89 | 0.17 | 0.35 | 0.01 | 0.18 |
| 23 | 81 | 0.39 | 1.08 | 0.03 | 0.48 |
| 24 | 70 | 0.19 | 0.67 | 0.22 | 0.36 |
| 27 | 86 | 0.27 | 0.83 | 0.02 | 0.33 |
| 28 | 55 | 1.07 | 0.68 | 0.07 | 0.28 |
| 29 | 83 | 0.28 | 0.10 | 0.02 | 0.03 |
| 30 | 62 | 1.35 | 0.67 | 0.03 | 0.16 |
| 32 | 87 | 0.44 | 0.48 | 0.03 | 0.19 |

Emission factors in terms of lbs/bbl can be calculated with the following formula:

$$\text{HAP Pollutant}_i \text{ (lbs/bbl)} = (\text{weight \% HAP Pollutant}_i/\text{weight \% VOC}_i) \times \text{VOC Emissions}_i \text{ (lbs/bbl)} \quad \text{(Eq. 3-1)}$$

Table 3-2 shows the VOC and BTEX emission factors for these 19 sites. As all data was obtained through testing, preferential weighting is not used to calculate the average emission factors.

## Table 3-2. VOC and BTEX Emission Factors

| Tank Battery Site # | Region | VOC Emission Factor (lbs/bbl) | Benzene Emission Factor (lbs/bbl) | Toluene Emission Factor (lbs/bbl) | Ethylbenzene Emission Factor (lbs/bbl) | Xylene Emission Factor (lbs/bbl) |
|---|---|---|---|---|---|---|
| 2 | Western Gulf | 3.65 | 0.0264 | 0.0412 | 0.0031 | 0.0163 |
| 3 | Western Gulf | 7.92 | 0.0805 | 0.1405 | 0.0077 | 0.0588 |
| 4 | Western Gulf | 0.78 | 0.0078 | 0.0140 | 0.0008 | 0.0056 |
| 5 | Western Gulf | 0.67 | 0.0072 | 0.0126 | 0.0007 | 0.0053 |
| 6 | Western Gulf | 2.96 | 0.0223 | 0.0255 | 0.0014 | 0.0064 |
| 13 | Fort Worth | 39.23 | 0.0920 | 0.1937 | 0.0048 | 0.0678 |
| 14 | Fort Worth | 29.51 | 0.0724 | 0.1837 | 0.0111 | 0.0891 |
| 15 | Fort Worth | 11.99 | 0.0263 | 0.0366 | 0.0015 | 0.0132 |
| 16 | Fort Worth | 60.58 | 0.1425 | 0.2922 | 0.0143 | 0.1354 |
| 18 | Fort Worth | 7.34 | 0.0241 | 0.0682 | 0.0031 | 0.0398 |
| 19 | Fort Worth | 13.16 | 0.0427 | 0.0991 | 0.0034 | 0.0427 |
| 20 | Fort Worth | 30.43 | 0.0581 | 0.1197 | 0.0034 | 0.0615 |
| 23 | Fort Worth | 5.56 | 0.0268 | 0.0741 | 0.0021 | 0.0329 |

## Table 3-2. VOC and BTEX Emission Factors

| Tank Battery Site # | Region | VOC Emission Factor (lbs/bbl) | Benzene Emission Factor (lbs/bbl) | Toluene Emission Factor (lbs/bbl) | Ethylbenzene Emission Factor (lbs/bbl) | Xylene Emission Factor (lbs/bbl) |
|---|---|---|---|---|---|---|
| 24 | Fort Worth | 4.22 | 0.0115 | 0.0404 | 0.0133 | 0.0217 |
| 27 | Fort Worth | 14.39 | 0.0452 | 0.1389 | 0.0033 | 0.0552 |
| 28 | Western Gulf | 4.17 | 0.0811 | 0.0516 | 0.0053 | 0.0212 |
| 29 | Western Gulf | 33.68 | 0.1136 | 0.0406 | 0.0081 | 0.0122 |
| 30 | Western Gulf | 6.11 | 0.1330 | 0.0660 | 0.0030 | 0.0158 |
| 32 | Western Gulf | 63.49 | 0.3211 | 0.3503 | 0.0219 | 0.1387 |
| Production-Weighted Average Emission Factor (lbs/bbl) | | | 0.0864 | 0.0981 | 0.0063 | 0.0387 |
| Arithmetic Average Emission Factor (lbs/bbl) | | | 0.0702 | 0.1047 | 0.0059 | 0.0442 |

## 3.2 BTEX Emissions Data Derived from the Barnett Shale Area Special Inventory, Phase II (2009)

TCEQ provided ERG with data from the “Barnett Shale Area Special Inventory, Phase II 2009” (Barnett Shale Inventory) information in spreadsheet format. The Barnett Shale Inventory data contains records of condensate tanks with reported condensate production rates and calculated BTEX emissions. ERG analyzed the BTEX emissions data and developed emission factors for condensate tanks in the Bend-Arch-Fort Worth and Barnett Shale counties. The data analysis was similar to that done for VOC for the entire Barnett Shale region. All records with emission factors above 140 lbs/bbl were rejected. Only records using the preferred estimation methods for flashing emissions (direct measurement, process simulator, E&P TANK, GOR) were analyzed. A production-weighted average of the emission factors, before controls, was calculated for each HAP pollutant as shown in Table 3-3. The data is grouped by estimation method, and a production-weighted average and an arithmetic average is used in determining an emission factor for each estimation method. The production-weighted average and arithmetic average for each estimation method were weighted according to the weighting factors in Table 2-11.

**Table 3-3. Condensate Tank BTEX Emission Factor Estimates Using Data from the Barnett Shale Phase II 2009 Inventory**

| Emission Calculation Methods | Pollutant | Total Emissions (lbs) | Total Production (bbl) | Production-Weighted Average Emission Factor (lbs/bbl) | Arithmetic Average Emission Factor (lbs/bbl) |
|---|---|---|---|---|---|
| Flash Emissions: Process Simulator Models, E&P TANK, Direct Measurement, GOR<br><br>Working and Breathing Emissions: E&P TANK, EPA TANKS Program, Other | Benzene | 17,393 | 723,298 | 0.019 | 0.084 |
| | Toluene | 28,926 | 734,626 | 0.042 | 0.13 |
| | Ethylbenzene | 2,057 | 310,139 | 0.011 | 0.036 |
| | Xylene | 20,047 | 730,722 | 0.067 | 0.20 |

## 3.3 BTEX Emissions Data Derived from E&P TANK Reports Submitted in Response to the ERG Survey

One respondent to the ERG Survey provided paper copies of the E&P Tank V 2.0 Calculation Reports for 85 well/tank sites. The E&P TANK reports contain detailed information on a tank, its equipment, and its emissions, including: API gravity, separator pressure, separator temperature, and annual liquids production; and annual emissions of methane, non-methane volatile organic compounds, benzene, toluene, ethylbenzene, and xylene. As E&P TANK is one of the methods preferred by TCEQ for calculating flashing, working, and breathing emissions, this data was used in evaluating BTEX emissions in the three regions (Eagle Ford Shale, East Texas/Haynesville Shale, and Western Gulf) in which the tanks are located. Eight sites produced liquids having an API gravity of less than 40 degrees, so these sites were removed from the dataset. Data from the remaining 77 records is shown in Table 3-4.

## Table 3-4. Condensate Tank BTEX Emission Factor Estimates Using Data from E&P TANK Reports Submitted for ERG Survey

| Region | County | API Gravity (deg.) | Separator Pressure (psig) | Condensate Production (bbl) | Emission Factors (lbs/bbl) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | VOC | Benzene | Toluene | Ethylbenzene | Xylene |
| Eagle Ford | Fayette | 49.2 | 25.4 | 2,555 | 0.53 | 0.0039 | 0.0078 | 0.0008 | 0.0047 |
| Eagle Ford | Fayette | 49.2 | 25.2 | 2,811 | 0.52 | 0.0043 | 0.0078 | 0.0007 | 0.0050 |
| Eagle Ford | Fayette | 49.2 | 28.5 | 2,190 | 0.58 | 0.0046 | 0.0091 | 0.0009 | 0.0055 |
| Eagle Ford | Lavaca | 40.8 | 35 | 949 | 0.27 | 0.6322 | 0.0358 | 0.0243 | 0.0084 |
| Eagle Ford | Leon | 45.2 | 14 | 1,460 | 0.92 | 0.0288 | 0.0055 | 0.0014 | 0.0055 |
| Eagle Ford | Leon | 45.2 | 52.9 | 219 | 1.28 | 0.0822 | 0.0183 | 0.0091 | 0.0183 |
| Eagle Ford | Leon | 45.2 | 108.9 | 256 | 1.33 | 0.0783 | 0.0157 | 0.0078 | 0.0235 |
| Eagle Ford | Leon | 45.2 | 64.1 | 146 | 1.51 | 0.1096 | 0.0274 | 0.0137 | 0.0274 |
| Eagle Ford | McMullen | 54.7 | 48 | 14,856 | 1.51 | 0.0059 | 0.0125 | 0.0003 | 0.0040 |
| Eagle Ford | McMullen | 54.7 | 48 | 8,322 | 1.80 | 0.0077 | 0.0166 | 0.0002 | 0.0053 |
| Eagle Ford | McMullen | 59.3 | 38 | 220,570 | 3.91 | 0.0226 | 0.0336 | 0.0007 | 0.0156 |
| Eagle Ford | McMullen | 59.3 | 38 | 86,943 | 3.94 | 0.0228 | 0.0340 | 0.0008 | 0.0157 |
| Eagle Ford | Webb | 64.5 | 65 | 149,139 | 3.42 | 0.0139 | 0.0172 | 0.0003 | 0.0077 |
| Eagle Ford | Webb | 64.5 | 200 | 276,816 | 3.47 | 0.0142 | 0.0176 | 0.0003 | 0.0079 |
| East Texas | Anderson | 42 | 58.8 | 37 | 1.64 | 0.1644 | 0.1644 | 0.0205 | 0.1096 |
| East Texas | Cherokee | 45.2 | 142.4 | 146 | 1.64 | 0.1096 | 0.0274 | 0.0137 | 0.0274 |
| East Texas | Cherokee | 45.2 | 76.9 | 256 | 1.33 | 0.0783 | 0.0157 | 0.0078 | 0.0235 |
| East Texas | Cherokee | 45.2 | 84.9 | 110 | 1.46 | 0.1096 | 0.0365 | 0.0183 | 0.0365 |
| East Texas | Freestone | 60 | 205 | 4,271 | 12.96 | 0.1892 | 0.1321 | 0.0037 | 0.0239 |
| East Texas | Freestone | 60 | 75.4 | 329 | 16.32 | 0.3592 | 0.2740 | 0.0061 | 0.0548 |
| East Texas | Freestone | 60 | 69.3 | 1,679 | 14.71 | 0.2418 | 0.1739 | 0.0048 | 0.0322 |
| East Texas | Freestone | 60 | 81.2 | 730 | 15.21 | 0.2767 | 0.2055 | 0.0055 | 0.0384 |
| East Texas | Freestone | 60 | 77.6 | 1,971 | 14.50 | 0.2334 | 0.1674 | 0.0051 | 0.0315 |
| East Texas | Harrison | 53.5 | 100 | 1,095 | 0.20 | 0.0091 | 0.0018 | 0.0004 | 0.0018 |
| East Texas | Henderson | 50.4 | 40 | 219 | 0.46 | 0.0457 | 0.0183 | 0.0057 | 0.0091 |
| East Texas | Henderson | 50.4 | 267.3 | 475 | 0.46 | 0.0253 | 0.0084 | 0.0032 | 0.0042 |
| East Texas | Henderson | 50.4 | 78.1 | 3,650 | 0.36 | 0.0077 | 0.0027 | 0.0010 | 0.0011 |
| East Texas | Henderson | 50.4 | 45.8 | 621 | 0.42 | 0.0193 | 0.0064 | 0.0024 | 0.0032 |
| East Texas | Henderson | 50.4 | 34 | 730 | 0.44 | 0.0192 | 0.0082 | 0.0024 | 0.0027 |
| East Texas | Henderson | 50.4 | 36 | 803 | 0.42 | 0.0174 | 0.0075 | 0.0022 | 0.0025 |

## Table 3-4. Condensate Tank BTEX Emission Factor Estimates Using Data from E&P TANK Reports Submitted for ERG Survey

| Region | County | API Gravity (deg.) | Separator Pressure (psig) | Condensate Production (bbl) | Emission Factors (lbs/bbl) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | VOC | Benzene | Toluene | Ethylbenzene | Xylene |
| East Texas | Houston | 50.6 | 40 | 219 | 0.18 | 0.0183 | 0.0091 | 0.0018 | 0.0051 |
| East Texas | Houston | 50.6 | 146.5 | 256 | 0.23 | 0.0157 | 0.0078 | 0.0016 | 0.0043 |
| East Texas | Houston | 50.6 | 54.5 | 183 | 0.22 | 0.0219 | 0.0110 | 0.0022 | 0.0061 |
| East Texas | Houston | 50.6 | 59.2 | 621 | 0.19 | 0.0064 | 0.0032 | 0.0006 | 0.0018 |
| East Texas | Limestone | 42 | 40 | 183 | 0.55 | 0.0767 | 0.0438 | 0.0015 | 0.0219 |
| East Texas | Limestone | 42 | 69.8 | 73 | 1.10 | 0.1370 | 0.1096 | 0.0027 | 0.0548 |
| East Texas | Limestone | 42 | 77.3 | 37 | 1.64 | 0.1644 | 0.1644 | 0.0033 | 0.1096 |
| East Texas | Limestone | 42 | 66.2 | 110 | 0.91 | 0.1096 | 0.0731 | 0.0022 | 0.0365 |
| East Texas | Limestone | 42 | 64.3 | 183 | 0.55 | 0.0767 | 0.0438 | 0.0015 | 0.0329 |
| East Texas | Marion | 45.2 | 20 | 876 | 0.98 | 0.0365 | 0.0068 | 0.0023 | 0.0091 |
| East Texas | Marion | 45.2 | 50 | 1,424 | 0.91 | 0.0281 | 0.0056 | 0.0014 | 0.0056 |
| East Texas | Marion | 45.2 | 40 | 840 | 1.02 | 0.0381 | 0.0071 | 0.0024 | 0.0095 |
| East Texas | Marion | 45.2 | 40 | 219 | 1.37 | 0.0822 | 0.0183 | 0.0091 | 0.0183 |
| East Texas | Nacogdoches | 58.8 | 807 | 110 | 1.28 | 0.0548 | 0.0731 | 0.0183 | 0.0913 |
| East Texas | Navarro | 46.3 | 38 | 6,023 | 3.22 | 0.0306 | 0.0186 | 0.0007 | 0.0040 |
| East Texas | Panola | 45.2 | 76 | 1,497 | 0.88 | 0.0281 | 0.0053 | 0.0013 | 0.0053 |
| East Texas | Panola | 45.2 | 102 | 4,709 | 0.76 | 0.0174 | 0.0030 | 0.0008 | 0.0038 |
| East Texas | Panola | 45.2 | 99.5 | 1,314 | 0.91 | 0.0304 | 0.0061 | 0.0015 | 0.0061 |
| East Texas | Panola | 45.2 | 90 | 2,044 | 0.88 | 0.0245 | 0.0039 | 0.0010 | 0.0049 |
| East Texas | Panola | 45.2 | 40.2 | 1,825 | 0.91 | 0.0252 | 0.0044 | 0.0011 | 0.0055 |
| East Texas | Rusk | 55.5 | 105 | 21,681 | 6.46 | 0.0540 | 0.0564 | 0.0017 | 0.0167 |
| East Texas | Rusk | 55.5 | 40 | 183 | 6.36 | 0.0548 | 0.0548 | 0.0034 | 0.0219 |
| East Texas | San Augustine | 58.8 | 168 | 146 | 1.10 | 0.0411 | 0.0548 | 0.0137 | 0.0685 |
| East Texas | Shelby | 58.8 | 40 | 1,460 | 0.33 | 0.0082 | 0.0082 | 0.0014 | 0.0096 |
| East Texas | Upshur | 55.6 | 230 | 1,095 | 20.31 | 0.2466 | 0.0731 | 0.0037 | 0.0511 |
| East Texas | Upshur | 55.6 | 112.4 | 4,818 | 21.02 | 0.2665 | 0.0797 | 0.0037 | 0.0556 |
| East Texas | Upshur | 55.6 | 233.2 | 730 | 19.78 | 0.2411 | 0.0712 | 0.0027 | 0.0493 |
| East Texas | Upshur | 55.6 | 222.7 | 1,095 | 21.39 | 0.2612 | 0.0767 | 0.0037 | 0.0530 |
| East Texas | Upshur | 55.6 | 215 | 3,030 | 20.73 | 0.2535 | 0.0753 | 0.0040 | 0.0522 |
| Western Gulf | Liberty | 49.9 | 50 | 511 | 1.06 | 0.0352 | 0.0783 | 0.0039 | 0.0391 |

## Table 3-4. Condensate Tank BTEX Emission Factor Estimates Using Data from E&P TANK Reports Submitted for ERG Survey

| Region | County | API Gravity (deg.) | Separator Pressure (psig) | Condensate Production (bbl) | Emission Factors (lbs/bbl) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | VOC | Benzene | Toluene | Ethylbenzene | Xylene |
| Western Gulf | Liberty | 53.9 | 25 | 475 | 1.35 | 0.0126 | 0.0421 | 0.0042 | 0.0337 |
| Western Gulf | Newton | 59.8 | 70 | 6,607 | 3.55 | 0.0061 | 0.0127 | 0.0009 | 0.0070 |
| Western Gulf | Newton | 59.8 | 70 | 2,373 | 3.57 | 0.0059 | 0.0126 | 0.0008 | 0.0067 |
| Western Gulf | Nueces | 49.2 | 20 | 6,789 | 0.36 | 0.0024 | 0.0044 | 0.0003 | 0.0027 |
| Western Gulf | Nueces | 49.2 | 20 | 1,935 | 0.60 | 0.0052 | 0.0093 | 0.0010 | 0.0062 |
| Western Gulf | Nueces | 51.9 | 35 | 3,723 | 0.59 | 0.0038 | 0.0064 | 0.0005 | 0.0043 |
| Western Gulf | Orange | 40.9 | 40 | 35,770 | 0.18 | 0.0003 | 0.0008 | 0.0001 | 0.0004 |
| Western Gulf | Orange | 40.9 | 40 | 1,351 | 0.47 | 0.0015 | 0.0044 | 0.0005 | 0.0030 |
| Western Gulf | San Patricio | 58.1 | 20 | 61,466 | 58.03 | 0.4031 | 0.3360 | 0.0257 | 0.1990 |
| Western Gulf | Starr | 49.2 | 213.8 | 438 | 1.05 | 0.0137 | 0.0320 | 0.0046 | 0.0183 |
| Western Gulf | Starr | 49.2 | 213.8 | 1,095 | 0.69 | 0.0073 | 0.0146 | 0.0018 | 0.0091 |
| Western Gulf | Starr | 49.2 | 215.7 | 949 | 0.74 | 0.0084 | 0.0148 | 0.0021 | 0.0105 |
| Western Gulf | Wharton | 47.2 | 30 | 10,001 | 0.60 | 0.0052 | 0.0126 | 0.0004 | 0.0060 |
| Western Gulf | Wharton | 47.2 | 32 | 2,519 | 0.85 | 0.0095 | 0.0222 | 0.0008 | 0.0111 |
| Western Gulf | Wharton | 47.2 | 31 | 767 | 1.12 | 0.0183 | 0.0470 | 0.0026 | 0.0235 |
| Western Gulf | Wharton | 47.2 | 27 | 3,650 | 0.75 | 0.0077 | 0.0181 | 0.0005 | 0.0088 |
| Western Gulf | Wharton | 47.2 | 25 | 1,570 | 0.89 | 0.0115 | 0.0280 | 0.0013 | 0.0140 |
| Arithmetic Average Emission Factor (lbs/bbl) | | | | | | 0.0772 | 0.0438 | 0.0040 | 0.0230 |
| Production-Weighted Average Emission Factor (lbs/bbl) | | | | | | 0.0465 | 0.0441 | 0.0022 | 0.0227 |

### 3.4 Summary of Findings and Recommended Regional BTEX Emission Factors

ERG compiled emission factor data for each region for which data was available using the data from the testing results (Table 3-2), Barnett Shale Area Special Inventory (Table 3-3), and the E&P TANK reports from the ERG survey (Table 3-4). Table 3-5 shows the production-weighted average emission factors for each region, before the effect of any controls. Table 3-6 shows the arithmetic average emission factors for each region, before the effect of any controls. A statewide average emission factor can be used in estimating BTEX emissions from condensate tanks in the other regions of the state (Anadarko, Palo Duro, Permian, and Marathon Thrust Belt).

**Table 3-5. Production-Weighted Average Regional BTEX Emission Factors, from Testing Data, Barnett Shale Inventory, and Survey Data**

| Region | Number of Data Points | Production-Weighted Average Emission Factors (lbs/bbl) | | | |
|---|---|---|---|---|---|
| | | Benzene | Toluene | Ethylbenzene | Xylene |
| Eagle Ford | 14 | 0.0181 | 0.0238 | 0.0005 | 0.0108 |
| East Texas | 45 | 0.0914 | 0.0512 | 0.0023 | 0.0190 |
| Fort Worth | 537 | 0.0164 | 0.0351 | 0.0068 | 0.0433 |
| Western Gulf | 30 | 0.0866 | 0.0829 | 0.0063 | 0.0429 |
| All Other Counties | - | 0.0385 | 0.0494 | 0.0063 | 0.0466 |

**Table 3-6. Arithmetic Average Regional BTEX Emission Factors, from Testing Data, Barnett Shale Inventory, and Survey Data**

| Region | Number of Data Points | Arithmetic Average Emission Factors (lbs/bbl) | | | |
|---|---|---|---|---|---|
| | | Benzene | Toluene | Ethylbenzene | Xylene |
| Eagle Ford | 14 | 0.0736 | 0.0185 | 0.0044 | 0.0110 |
| East Texas | 45 | 0.0968 | 0.0537 | 0.0044 | 0.0270 |
| Fort Worth | 537 | 0.0956 | 0.1574 | 0.0222 | 0.1571 |
| Western Gulf | 30 | 0.0562 | 0.0552 | 0.0041 | 0.0244 |
| All Other Counties | - | 0.0998 | 0.1389 | 0.0161 | 0.1491 |

# 4.0 Recommendations for Future Condensate Tank Investigations

ERG makes the following recommendations with respect to future investigations.

- The timing of this survey coincided with the requirement for many producers to file information with EPA in compliance with Subpart W of the Greenhouse Gas rules. Based upon discussions with survey recipients, this had a negative impact on survey participation by producers.

- If high participation rates are required, ERG recommends that the TCEQ consider collecting information from oil and gas producers through mandatory information collection requests. If mandatory surveys are not feasible, then any voluntary survey should be initiated with a list of the environmental contacts at each of the companies to be surveyed.

- A consistent definition of condensate based on API gravity should be developed by TCEQ in combination with the RRC so that the most appropriate emission factors are applied to tank liquids, including those tanks that store what operators consider to be a combination of oil and condensate.

# 5.0 Natural Gas Composition Data Collection and Analysis

In June of 2012, ERG staff visited TCEQ's office in Austin to review annual point source emissions inventory reports submitted by facilities throughout Texas identified as having dehydrators on site. The purpose of this visit was to obtain copies of GLYCalc reports to obtain natural gas composition data. GLYCalc is a software tool used to estimate emissions from dehydrators. Required GLYCalc inputs include natural gas composition data, temperature, and pressure.

TCEQ originally identified a possible 368 facilities across the state with dehydrators. ERG reviewed these files and obtained approximately 240 inventory reports related to dehydrator emissions, including many GLYCalc reports. These reports were reviewed and all incomplete reports were flagged and set aside. These incomplete reports did not contain natural gas stream composition data, or contained data in a format inconsistent with the GLYCalc reporting or output forms and were not evaluated further.

Ultimately, ERG was able to compile complete GLYCalc data for 157 sites located in 64 counties. Based on TCEQ's initial identification of 368 facilities, there are 101 counties in Texas that contain sites with dehydrators that submit an annual point source emissions inventory.

The following constituents were available in the GLYCalc natural gas stream composition data (% volume):

- Water,
- Carbon Dioxide ($CO_2$),
- Hydrogen Sulfide,
- Nitrogen,
- Methane,
- Ethane,
- Propane,
- Isobutane,
- n-Butane,
- Isopentane,
- n-Pentane,
- Cyclopentane,
- n-Hexane,
- Cyclohexane,
- Other Hexanes,
- Heptanes,
- Methylcyclohexane,
- Benzene,
- Toluene,

- Ethylbenzene,
- Xylenes, and
- C8+ Heavies

The natural gas stream composition data, both for dry stream and wet stream, were then transcribed into Microsoft Excel spreadsheets. This spreadsheet file consisted of composition data for 314 natural gas streams (wet and dry) in 64 counties. Once the data transcription was complete, these data were quality assured for accuracy and completeness. During the Quality Assurance (QA) steps, ERG staff identified a few data points that seemed indicative of a $CO_2$ well instead of a natural gas well. The $CO_2$ concentration for these streams was above 85% (by volume). These data points were present in Kent, Pecos, and Terrell counties. These data were excluded from further analysis. Also, the excluded data for Kent and Terrell counties were the only data points available for these two counties. Table 5-1, below, lists the number of GLYCalc reports used in the analysis by natural gas stream type and County.

**Table 5-1. Counties Included in the Natural Gas Composition Analysis**

| County | Dry Gas Stream | Wet Gas Stream | County | Dry Gas Stream | Wet Gas Stream |
|---|---|---|---|---|---|
| Anderson | 2 | 2 | Jack | 1 | 1 |
| Atascosa | 1 | 1 | Jefferson | 1 | 1 |
| Bastrop | 1 | 1 | Johnson | 17 | 17 |
| Brazoria | 11 | 11 | Kenedy | 1 | 1 |
| Brooks | 3 | 3 | Kent [a] | 1 | 1 |
| Caldwell | 1 | 1 | Liberty | 7 | 7 |
| Callahan | 1 | 1 | Martin | 1 | 1 |
| Camp | 1 | 1 | Matagorda | 2 | 2 |
| Carson | 1 | 1 | Montague | 1 | 1 |
| Cass | 1 | 1 | Nacogdoches | 2 | 2 |
| Chambers | 1 | 1 | Nueces | 1 | 1 |
| Clay | 2 | 2 | Orange | 2 | 2 |
| Coke | 1 | 1 | Palo Pinto | 1 | 1 |
| Crockett | 4 | 4 | Panola | 2 | 2 |
| De Witt | 1 | 1 | Parker | 5 | 5 |
| Denton | 2 | 2 | Pecos [a] | 4 | 4 |
| Eastland | 2 | 2 | Refugio | 2 | 2 |
| Erath | 1 | 1 | Robertson | 1 | 1 |
| Fort Bend | 1 | 1 | Rusk | 2 | 2 |
| Freestone | 5 | 5 | San Patricio | 2 | 2 |
| Gaines | 1 | 1 | Smith | 3 | 3 |
| Galveston | 3 | 3 | Sterling | 2 | 2 |
| Gray | 1 | 1 | Tarrant | 12 | 12 |
| Gregg | 4 | 4 | Terrell [a] | 1 | 1 |
| Hansford | 1 | 1 | Upshur | 1 | 2 |
| Hardin | 2 | 2 | Upton | 1 | 0 |
| Harris | 6 | 6 | Ward | 1 | 1 |

### Table 5-1. Counties Included in the Natural Gas Composition Analysis

| County | Dry Gas Stream | Wet Gas Stream | County | Dry Gas Stream | Wet Gas Stream |
|---|---|---|---|---|---|
| Harrison | 3 | 3 | Webb | 1 | 1 |
| Hemphill | 1 | 1 | Wheeler | 1 | 1 |
| Henderson | 2 | 2 | Wilbarger | 1 | 1 |
| Hood | 1 | 1 | Winkler | 1 | 1 |
| Houston | 1 | 1 | Wise | 5 | 5 |
| Irion | 1 | 1 | Young | 1 | 1 |
| | | | **Total** | **157** | **157** |

[a] As described above, the data for Kent and Terrell counties was not used and only 3 of the 4 records for Pecos county were used.

After all the QA checks were completed, average county profiles were developed for the counties for which natural gas composition data were available (listed in Table 5-1 above). Both wet and dry natural gas composition averages were calculated. The 64 counties for which data were available were then grouped by basins (Anadarko, Bend Arch-Forth Worth, East Texas, Permian, and Western Gulf Basins). Basin-level average natural gas composition (wet and dry) profiles were calculated for all the basins where data was available at county level. No data were available for counties in Marathon Thrust Belt Basin and Palo Duro Basin. Table 5-2 lists the counties in Marathon Thrust Belt Basin and Palo Duro Basin.

### Table 5-2. List of Counties Located in Marathon Thrust Belt Basin and Palo Duro Basin

| Basin | Counties | |
|---|---|---|
| Marathon Thrust Belt | Brewster | Terrell |
| Palo Duro Basin | Armstrong | Hale |
| | Bailey | Hall |
| | Briscoe | Hartley |
| | Castro | Lamb |
| | Childress | Motley |
| | Collingsworth | Oldham |
| | Cottle | Parmer |
| | Dallam | Potter |
| | Deaf Smith | Randall |
| | Donley | Swisher |
| | Floyd | |

Basin-level average natural gas composition profile and state-level average profile were then allocated to counties with no data based on which basin the county was located in. Except for the counties listed in Table 5-2, basin-level average profiles were allocated to all counties with no GLYCalc reports available. For the counties in Marathon Thrust Belt and Palo Duro basin, state-level average profile was allocated. Table 5-3 below

## Table 5-3. Basin-Level and State-Level Average Natural Gas Stream Composition Profiles

| Composition in % Volume | Anadarko Basin | | Bend Arch-Fort Worth Basin | | East Texas Basin | | Permian Basin | | Western Gulf | | State Profile | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream | Dry Stream | Wet Stream |
| Water | 0.04 | 0.13 | 0.01 | 0.12 | 0.01 | 0.12 | 0.01 | 0.15 | 0.01 | 0.12 | 0.01 | 0.12 |
| Carbon Dioxide | 0.64 | 0.65 | 1.74 | 1.74 | 1.72 | 1.71 | 0.95 | 0.90 | 1.13 | 1.14 | 1.43 | 1.44 |
| Hydrogen Sulfide | 0.03 | 0.03 | 0.001 | 0.001 | 0.0004 | 0.0004 | 0.11 | 0.11 | 0.0003 | 0.25 | 0.03 | 0.09 |
| Nitrogen | 1.35 | 1.34 | 1.74 | 1.73 | 0.88 | 0.87 | 2.14 | 2.18 | 0.51 | 0.49 | 1.20 | 1.19 |
| Methane | 90.76 | 90.68 | 87.91 | 87.59 | 91.73 | 91.49 | 80.43 | 78.53 | 90.07 | 89.94 | 88.67 | 88.36 |
| Ethane | 3.99 | 3.98 | 5.23 | 5.21 | 3.57 | 3.64 | 9.02 | 9.07 | 4.51 | 4.51 | 5.03 | 5.00 |
| Propane | 1.74 | 1.74 | 2.14 | 2.18 | 1.04 | 1.06 | 4.48 | 5.39 | 2.04 | 2.05 | 2.13 | 2.21 |
| Isobutane | 0.26 | 0.26 | 0.31 | 0.32 | 0.28 | 0.29 | 0.51 | 0.61 | 0.48 | 0.48 | 0.38 | 0.40 |
| n-Butane | 0.54 | 0.54 | 0.62 | 0.68 | 0.31 | 0.32 | 1.19 | 1.63 | 0.51 | 0.51 | 0.58 | 0.64 |
| Isopentane | 0.16 | 0.16 | 0.20 | 0.22 | 0.15 | 0.17 | 0.35 | 0.40 | 0.24 | 0.24 | 0.22 | 0.23 |
| n-Pentane | 0.17 | 0.17 | 0.27 | 0.29 | 0.11 | 0.12 | 0.32 | 0.44 | 0.17 | 0.17 | 0.20 | 0.22 |
| Cyclopentane | 0.01 | 0.01 | 0.03 | 0.04 | 0.04 | 0.04 | 0.01 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 |
| n-Hexane | 0.10 | 0.06 | 0.05 | 0.12 | 0.05 | 0.05 | 0.16 | 0.18 | 0.05 | 0.06 | 0.06 | 0.09 |
| Cyclohexane | 0.01 | 0.01 | 0.04 | 0.03 | 0.03 | 0.03 | 0.09 | 0.11 | 0.05 | 0.06 | 0.04 | 0.05 |
| Other Hexanes | 0.14 | 0.14 | 0.07 | 0.06 | 0.10 | 0.11 | 0.24 | 0.29 | 0.17 | 0.15 | 0.13 | 0.13 |
| Heptanes | 0.06 | 0.06 | 0.08 | 0.08 | 0.06 | 0.07 | 0.14 | 0.14 | 0.07 | 0.09 | 0.08 | 0.08 |
| Methylcyclohexane | 0.02 | 0.02 | 0.02 | 0.02 | 0.01 | 0.02 | 0.04 | 0.04 | 0.04 | 0.04 | 0.03 | 0.04 |
| Benzene | 0.01 | 0.01 | 0.01 | 0.01 | 0.02 | 0.03 | 0.07 | 0.08 | 0.01 | 0.02 | 0.02 | 0.02 |
| Toluene | 0.01 | 0.01 | 0.003 | 0.003 | 0.01 | 0.01 | 0.04 | 0.04 | 0.01 | 0.02 | 0.01 | 0.01 |
| Ethylbenzene | 0.001 | 0.001 | 0.0005 | 0.001 | 0.001 | 0.001 | 0.01 | 0.01 | 0.001 | 0.002 | 0.001 | 0.002 |
| Xylenes | 0.003 | 0.01 | 0.002 | 0.003 | 0.002 | 0.005 | 0.01 | 0.01 | 0.003 | 0.01 | 0.003 | 0.005 |
| C8+ Heavies | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.04 | 0.07 | 0.07 | 0.11 | 0.11 | 0.06 | 0.06 |

presents the basin-level and state-level average natural gas stream composition profiles for both wet and dry natural gas streams.

Based on the basin and state level average natural gas composition profiles, the methane composition varies from 78% to 91%. However, individual GLYCalc reports indicated as high as 97.8% methane. Table 5-4 indicates the average natural gas composition profile allocation scheme that was adopted for counties where GLYCalc reports were not available. Figure 5-1 presents a distribution of methane concentrations across all Texas counties. Detailed county-level natural gas composition profile data are presented in Attachment D.

## Table 5-4. Average Natural Gas Composition Profile Allocation Scheme

| County | Profile Allocation | Basin | County | Profile Allocation | Basin |
|---|---|---|---|---|---|
| Anderson | Average County | | Karnes | Average Basin | Western Gulf |
| Andrews | Average Basin | Permian Basin | Kaufman | Average Basin | East Texas Basin |
| Angelina | Average Basin | East Texas Basin | Kendall | Average Basin | Bend Arch-Fort Worth Basin |
| Aransas | Average Basin | Western Gulf | Kenedy | Average County | |
| Archer | Average Basin | Bend Arch-Fort Worth Basin | Kent[1] | Average Basin | Permian Basin |
| Armstrong | Average State | Palo Duro Basin | Kerr | Average Basin | Bend Arch-Fort Worth Basin |
| Atascosa | Average County | | Kimble | Average Basin | Bend Arch-Fort Worth Basin |
| Austin | Average Basin | Western Gulf | King | Average Basin | Permian Basin |
| Bailey | Average State | Palo Duro Basin | Kinney | Average Basin | Western Gulf |
| Bandera | Average Basin | Bend Arch-Fort Worth Basin | Kleberg | Average Basin | Western Gulf |
| Bastrop | Average County | | Knox | Average Basin | Bend Arch-Fort Worth Basin |
| Baylor | Average Basin | Bend Arch-Fort Worth Basin | La Salle | Average Basin | Western Gulf |
| Bee | Average Basin | Western Gulf | Lamar | Average Basin | East Texas Basin |
| Bell | Average Basin | Western Gulf | Lamb | Average State | Palo Duro Basin |
| Bexar | Average Basin | Western Gulf | Lampasas | Average Basin | Bend Arch-Fort Worth Basin |
| Blanco | Average Basin | Bend Arch-Fort Worth Basin | Lavaca | Average Basin | Western Gulf |
| Borden | Average Basin | Permian Basin | Lee | Average Basin | Western Gulf |
| Bosque | Average Basin | Bend Arch-Fort Worth Basin | Leon | Average Basin | East Texas Basin |
| Bowie | Average Basin | East Texas Basin | Liberty | Average County | |
| Brazoria | Average County | | Limestone | Average Basin | East Texas Basin |
| Brazos | Average Basin | Western Gulf | Lipscomb | Average Basin | Anadarko Basin |
| Brewster | Average State | Marathon Thrust Belt | Live Oak | Average Basin | Western Gulf |
| Briscoe | Average State | Palo Duro Basin | Llano | Average Basin | Bend Arch-Fort Worth Basin |
| Brooks | Average County | | Loving | Average Basin | Permian Basin |
| Brown | Average Basin | Bend Arch-Fort Worth Basin | Lubbock | Average Basin | Permian Basin |
| Burleson | Average Basin | Western Gulf | Lynn | Average Basin | Permian Basin |
| Burnet | Average Basin | Bend Arch-Fort Worth Basin | Madison | Average Basin | Western Gulf |

## Table 5-4. Average Natural Gas Composition Profile Allocation Scheme

| County | Profile Allocation | Basin | County | Profile Allocation | Basin |
|---|---|---|---|---|---|
| Caldwell | Average County | | Marion | Average Basin | East Texas Basin |
| Calhoun | Average Basin | Western Gulf | Martin | Average County | |
| Callahan | Average County | | Mason | Average Basin | Bend Arch-Fort Worth Basin |
| Cameron | Average Basin | Western Gulf | Matagorda | Average County | |
| Camp | Average County | | Maverick | Average Basin | Western Gulf |
| Carson | Average County | | McCulloch | Average Basin | Bend Arch-Fort Worth Basin |
| Cass | Average County | | McLennan | Average Basin | Bend Arch-Fort Worth Basin |
| Castro | Average State | Palo Duro Basin | McMullen | Average Basin | Western Gulf |
| Chambers | Average County | | Medina | Average Basin | Western Gulf |
| Cherokee | Average Basin | East Texas Basin | Menard | Average Basin | Bend Arch-Fort Worth Basin |
| Childress | Average State | Palo Duro Basin | Midland | Average Basin | Permian Basin |
| Clay | Average County | | Milam | Average Basin | Western Gulf |
| Cochran | Average Basin | Permian Basin | Mills | Average Basin | Bend Arch-Fort Worth Basin |
| Coke | Average County | | Mitchell | Average Basin | Permian Basin |
| Coleman | Average Basin | Bend Arch-Fort Worth Basin | Montague | Average County | |
| Collin | Average Basin | Bend Arch-Fort Worth Basin | Montgomery | Average Basin | Western Gulf |
| Collingsworth | Average State | Palo Duro Basin | Moore | Average Basin | Anadarko Basin |
| Colorado | Average Basin | Western Gulf | Morris | Average Basin | East Texas Basin |
| Comal | Average Basin | Western Gulf | Motley | Average State | Palo Duro Basin |
| Comanche | Average Basin | Bend Arch-Fort Worth Basin | Nacogdoches | Average County | |
| Concho | Average Basin | Bend Arch-Fort Worth Basin | Navarro | Average Basin | East Texas Basin |
| Cooke | Average Basin | Bend Arch-Fort Worth Basin | Newton | Average Basin | Western Gulf |
| Coryell | Average Basin | Bend Arch-Fort Worth Basin | Nolan | Average Basin | Permian Basin |
| Cottle | Average State | Palo Duro Basin | Nueces | Average County | |
| Crane | Average Basin | Permian Basin | Ochiltree | Average Basin | Anadarko Basin |
| Crockett | Average County | | Oldham | Average State | Palo Duro Basin |
| Crosby | Average Basin | Permian Basin | Orange | Average County | |
| Culberson | Average Basin | Permian Basin | Palo Pinto | Average County | |

## Table 5-4. Average Natural Gas Composition Profile Allocation Scheme

| County | Profile Allocation | Basin | County | Profile Allocation | Basin |
|---|---|---|---|---|---|
| Dallam | Average State | Palo Duro Basin | Panola | Average County | |
| Dallas | Average Basin | Bend Arch-Fort Worth Basin | Parker | Average County | |
| Dawson | Average Basin | Permian Basin | Parmer | Average State | Palo Duro Basin |
| De Witt | Average County | | Pecos[1] | Average County | |
| Deaf Smith | Average State | Palo Duro Basin | Polk | Average Basin | Western Gulf |
| Delta | Average Basin | East Texas Basin | Potter | Average State | Palo Duro Basin |
| Denton | Average County | | Presidio | Average Basin | Permian Basin |
| Dickens | Average Basin | Permian Basin | Rains | Average Basin | East Texas Basin |
| Dimmit | Average Basin | Western Gulf | Randall | Average State | Palo Duro Basin |
| Donley | Average State | Palo Duro Basin | Reagan | Average Basin | Permian Basin |
| Duval | Average Basin | Western Gulf | Real | Average Basin | Bend Arch-Fort Worth Basin |
| Eastland | Average County | | Red River | Average Basin | East Texas Basin |
| Ector | Average Basin | Permian Basin | Reeves | Average Basin | Permian Basin |
| Edwards | Average Basin | Permian Basin | Refugio | Average County | |
| El Paso | Average Basin | Permian Basin | Roberts | Average Basin | Anadarko Basin |
| Ellis | Average Basin | Bend Arch-Fort Worth Basin | Robertson | Average County | |
| Erath | Average County | | Rockwall | Average Basin | East Texas Basin |
| Falls | Average Basin | East Texas Basin | Runnels | Average Basin | Bend Arch-Fort Worth Basin |
| Fannin | Average Basin | East Texas Basin | Rusk | Average County | |
| Fayette | Average Basin | Western Gulf | Sabine | Average Basin | East Texas Basin |
| Fisher | Average Basin | Permian Basin | San Augustine | Average Basin | East Texas Basin |
| Floyd | Average State | Palo Duro Basin | San Jacinto | Average Basin | Western Gulf |
| Foard | Average Basin | Bend Arch-Fort Worth Basin | San Patricio | Average County | |
| Fort Bend | Average County | | San Saba | Average Basin | Bend Arch-Fort Worth Basin |
| Franklin | Average Basin | East Texas Basin | Schleicher | Average Basin | Permian Basin |
| Freestone | Average County | | Scurry | Average Basin | Permian Basin |
| Frio | Average Basin | Western Gulf | Shackelford | Average Basin | Bend Arch-Fort Worth Basin |
| Gaines | Average County | | Shelby | Average Basin | East Texas Basin |
| Galveston | Average County | | Sherman | Average Basin | Anadarko Basin |

## Table 5-4. Average Natural Gas Composition Profile Allocation Scheme

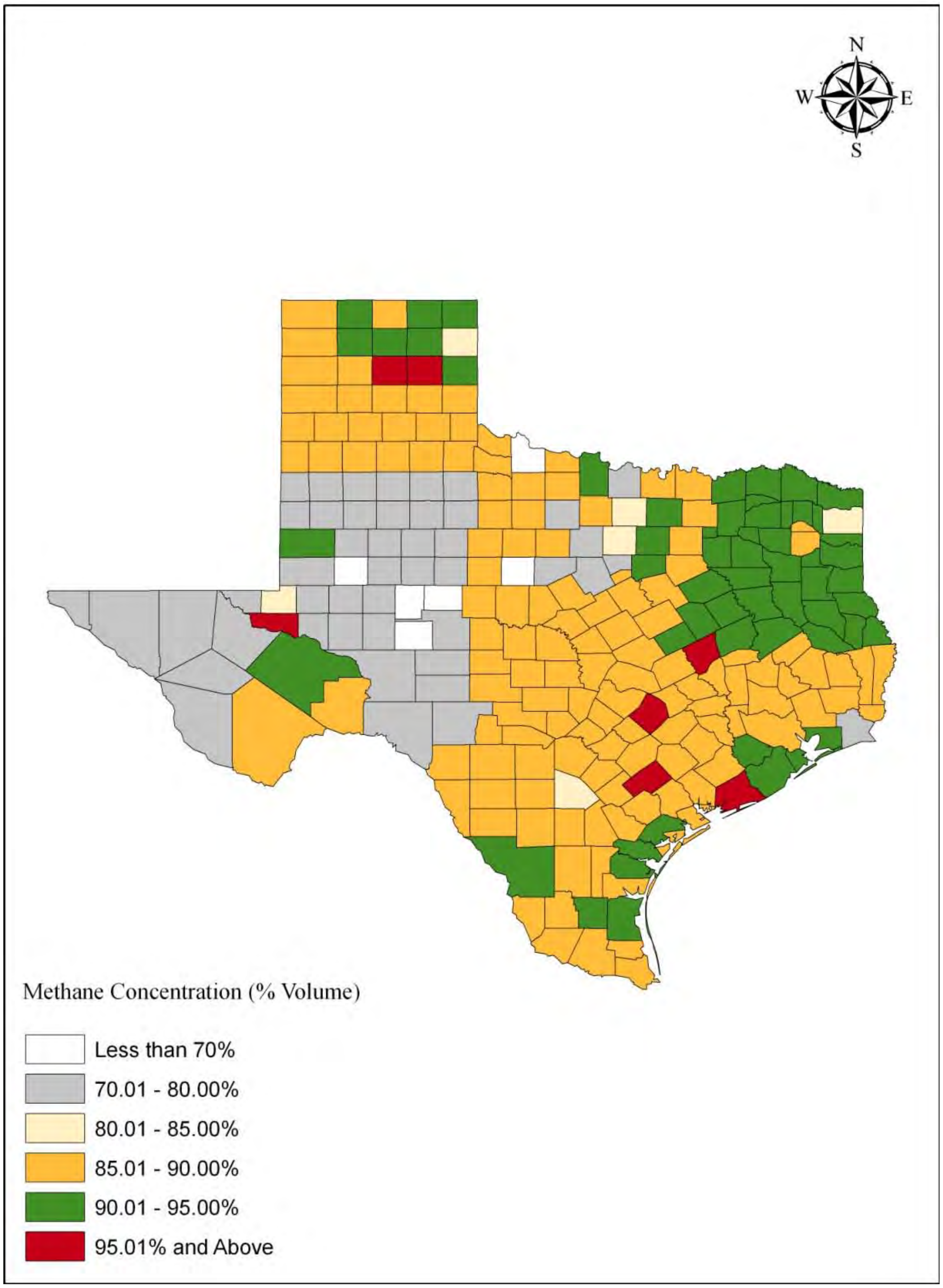
| County | Profile Allocation | Basin | County | Profile Allocation | Basin |
|---|---|---|---|---|---|
| Garza | Average Basin | Permian Basin | Smith | Average County | |
| Gillespie | Average Basin | Bend Arch-Fort Worth Basin | Somervell | Average Basin | Bend Arch-Fort Worth Basin |
| Glasscock | Average Basin | Permian Basin | Starr | Average Basin | Western Gulf |
| Goliad | Average Basin | Western Gulf | Stephens | Average Basin | Bend Arch-Fort Worth Basin |
| Gonzales | Average Basin | Western Gulf | Sterling | Average County | |
| Gray | Average County | | Stonewall | Average Basin | Permian Basin |
| Grayson | Average Basin | Bend Arch-Fort Worth Basin | Sutton | Average Basin | Permian Basin |
| Gregg | Average County | | Swisher | Average State | Palo Duro Basin |
| Grimes | Average Basin | Western Gulf | Tarrant | Average County | |
| Guadalupe | Average Basin | Western Gulf | Taylor | Average Basin | Bend Arch-Fort Worth Basin |
| Hale | Average State | Palo Duro Basin | Terrell[1] | Average State | Marathon Thrust Belt |
| Hall | Average State | Palo Duro Basin | Terry | Average Basin | Permian Basin |
| Hamilton | Average Basin | Bend Arch-Fort Worth Basin | Throckmorton | Average Basin | Bend Arch-Fort Worth Basin |
| Hansford | Average County | | Titus | Average Basin | East Texas Basin |
| Hardeman | Average Basin | Bend Arch-Fort Worth Basin | Tom Green | Average Basin | Permian Basin |
| Hardin | Average County | | Travis | Average Basin | Western Gulf |
| Harris | Average County | | Trinity | Average Basin | Western Gulf |
| Harrison | Average County | | Tyler | Average Basin | Western Gulf |
| Hartley | Average State | Palo Duro Basin | Upshur | Average County | |
| Haskell | Average Basin | Bend Arch-Fort Worth Basin | Upton[2] | Average County/Average Basin | Permian Basin |
| Hays | Average Basin | Western Gulf | Uvalde | Average Basin | Western Gulf |
| Hemphill | Average County | | Val Verde | Average Basin | Permian Basin |
| Henderson | Average County | | Van Zandt | Average Basin | East Texas Basin |
| Hidalgo | Average Basin | Western Gulf | Victoria | Average Basin | Western Gulf |
| Hill | Average Basin | Bend Arch-Fort Worth Basin | Walker | Average Basin | Western Gulf |
| Hockley | Average Basin | Permian Basin | Waller | Average Basin | Western Gulf |
| Hood | Average County | | Ward | Average County | |
| Hopkins | Average Basin | East Texas Basin | Washington | Average Basin | Western Gulf |
| Houston | Average County | | Webb | Average County | |

## Table 5-4. Average Natural Gas Composition Profile Allocation Scheme

| County | Profile Allocation | Basin | County | Profile Allocation | Basin |
|---|---|---|---|---|---|
| Howard | Average Basin | Permian Basin | Wharton | Average Basin | Western Gulf |
| Hudspeth | Average Basin | Permian Basin | Wheeler | Average County | |
| Hunt | Average Basin | East Texas Basin | Wichita | Average Basin | Bend Arch-Fort Worth Basin |
| Hutchinson | Average Basin | Anadarko Basin | Wilbarger | Average County | |
| Irion | Average County | | Willacy | Average Basin | Western Gulf |
| Jack | Average County | | Williamson | Average Basin | Western Gulf |
| Jackson | Average Basin | Western Gulf | Wilson | Average Basin | Western Gulf |
| Jasper | Average Basin | Western Gulf | Winkler | Average County | |
| Jeff Davis | Average Basin | Permian Basin | Wise | Average County | |
| Jefferson | Average County | | Wood | Average Basin | East Texas Basin |
| Jim Hogg | Average Basin | Western Gulf | Yoakum | Average Basin | Permian Basin |
| Jim Wells | Average Basin | Western Gulf | Young | Average County | |
| Johnson | Average County | | Zapata | Average Basin | Western Gulf |
| Jones | Average Basin | Bend Arch-Fort Worth Basin | Zavala | Average Basin | Western Gulf |

[1]These counties had GLYCalc reports that were flagged as potential $CO_2$ wells and excluded from further analysis.
[2]Upton county had 1 GLYCalc report and that report did not include wet gas stream composition data.

**Figure 5-1. Natural Gas Methane Composition Distribution across Texas Counties**



**Attachment A**
**Survey Letter**

Dear [Owner/Operator Contact Name]: [Date]

Eastern Research Group (ERG), an independent research organization, is conducting a study on condensate storage tank emissions for the Texas Commission on Environmental Quality (TCEQ). The purpose of this study is to develop updated county- and region-specific emission factors for estimating condensate storage tank emissions for each of the regions in Texas. The study results will assist the TCEQ in refining the emission factors used to develop the Texas area source oil and gas air emissions inventory.

Condensate tank flashing, working, and breathing emissions of volatile organic compounds (VOC) are currently estimated using an emission factor from a 2006 Texas Environmental Research Consortium study entitled: "VOC Emissions from Oil and Condensate Storage Tanks". TCEQ uses this emission factor to develop county-level area source VOC emissions estimates from condensate tanks at upstream oil and gas operations. To further increase the accuracy of the area source inventory, the TCEQ is seeking information from operators to assist in development of a refined county-specific condensate tank emission factor.

We are asking for your ***voluntary participation*** in this study of emissions from condensate tanks at gas wells in Texas that were in production during 2011. The study will involve sharing information regarding condensate production and measured or estimated emissions from condensate tank(s). ***Individual wells and tanks do not need to be identified.*** The information your company provides will be used for statistical purposes only in order to develop county-level and basin-level estimates and will not be republished or disseminated for other purposes.

ERG will contact your company via phone to discuss this effort and collect any information you are willing to share. We are seeking basin-specific condensate tank emissions information for gas wells in the [Insert Basin_Specific_Text]. The specific information we are requesting for each condensate tank battery includes:

- County
- 2011 VOC emissions
- 2011 condensate production
- Emissions estimation method
- Control technology
- Control efficiency
- API gravity
- Separator pressure

A table on the reverse side of this letter shows the type of data we wish to collect.

We appreciate your assistance in this important study. Questions concerning the scope of this study or ERG's relationship with TCEQ may be directed to the TCEQ Project Manager, Miles Whitten, at (512) 239-5479, or via email at miles.whitten@tceq.texas.gov. If you have any questions on the technical aspects of the study, please feel free to contact me at (919) 468-7902, or via email at stephen.treimel@erg.com.

Sincerely,

Stephen Treimel
Environmental Scientist
Eastern Research Group, Inc.

# Attachment B
# Survey Materials – Word Table and Excel Spreadsheet

Operator Name: [Insert Operator_Name]

Basin : [Insert Basin_Name_and_Counties]

| County | Condensate API Gravity (degrees) | Separator Pressure (psig) | 2011 Condensate Production (bbl) | 2011 VOC Emissions (tons) | Emissions Estimation Method (Testing, E&P Tank, Process Simulation model, GOR, HARC 051C, etc.) | Are Emissions vented, controlled, or recovered? | If controlled or recovered, what technology is used? | If controlled or recovered, what is the control or recovery efficiency? |
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**Texas Commission on Environmental Quality - Condensate Tank Emissions Survey**

**Instructions:** Provide the data listed below for up to ten separate condensate tank batteries located in the counties listed below. To avoid biasing the survey results, we ask that you please select the tanks at random from all of your producing wells in this region.

Operator Name:

Basin (Counties) : Anadarko basin (Hemphill, Lipscomb, Ochiltree, Roberts, and Wheeler counties).

| County | Condensate API Gravity (degrees) | Separator Pressure (psig) | 2011 Condensate Production (bbl) | 2011 VOC Emissions (tons) (flashing, working, & breathing) | Emissions Estimation Method (Testing, E&P Tank, Process Simulation model, GOR, HARC 051C, TANKS 4.0, etc) | Are Emissions vented, controlled, or recovered? | If controlled or recovered, what technology is used? | If controlled or recovered, what is the control or recovery efficiency? |
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Completed surveys can be emailed to me at stephen.treimel@erg.com or printed and mailed to: Eastern Research Group, 1600 Perimeter Park Drive, Morrisville, NC 27560.

**Attachment C**
**Condensate Tank Emissions Data**
**(Condensate_Tank_Data.xlsx)**

**Attachment D**
**County-Level Average Natural Gas Composition Profiles**
**(NG_Composition_Profiles.xlsx)**

# Exhibit 4

# Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Revisions to $CO_2$ Emissions Estimation Methodologies

This memo describes revisions implemented for multiple segments of natural gas and petroleum systems in the 2018 Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHGI). The revisions focus on $CO_2$ emissions calculation methodologies, but for certain sources, both the $CH_4$ and $CO_2$ calculation methodologies were revised. Previous versions of this memo were released in June and October 2017.[1,2]

The EPA made $CO_2$ methodological revisions for sources and segments that already rely on a subpart W-based $CH_4$ emission calculation methodology or where the $CH_4$ calculation methodology was otherwise recently revised. The subpart W methodology revisions for $CH_4$ emissions estimates are documented in the following memos: the 2014 HF Completion and Workover memo,[3] 2015 HF Completion and Workover memo,[4] 2016 Transmission memo,[5] 2016 Production memo,[6] 2017 Production memo,[7] and 2017 Processing memo.[8] The revisions discussed in this memo create consistency between $CH_4$ and $CO_2$ calculation methodologies. In addition, the EPA updated the GHGI to include both the $CO_2$ emissions and the relatively minor $CH_4$ emissions from flare stacks reported under subpart W in the production and transmission and storage segments.

The sources discussed in this memo include: production segment storage tanks, associated gas venting and flaring, hydraulically fractured (HF) gas well completions and workovers, production segment pneumatic controllers, production segment pneumatic pumps, liquids unloading, production segment miscellaneous flaring, most sources in the gas processing segment, transmission station flares, underground natural gas storage flares, and transmission and storage pneumatic controllers. The EPA did not consider revisions to the distribution segment $CO_2$ emissions calculation methodology, as discussed in Section 1.2.

## 1. Background and GHGI Methodology for $CO_2$ Emissions

This section discusses the GHGI methodology for calculating $CO_2$ emissions. Section 1.1 describes a $CO_2$-to-$CH_4$ gas content ratio methodology, which is the default approach used in all GHGI segments. This methodology was applied for numerous sources for the 2017 GHGI, and is still used in the 2018 GHGI for certain sources (excluding those sources with revisions in section 3). Section 1.2 describes the previous GHGI methodology to calculate $CO_2$

[1] See https://www.epa.gov/sites/production/files/2017-06/documents/updates_under_consideration_for_2018_ghgi_emissions_for_co2_from_natural_gas_and_petroleum_systems.pdf.
[2] See https://www.epa.gov/sites/production/files/2017-10/documents/2018_ghgi_co2_revisions_under_consideration_2017-10-25_to_post.pdf.
[3] "Overview of Update to Methodology for Hydraulically Fractured Gas Well Completions and Workovers in the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (2014 Inventory)," available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-updates-1990-2012-inventory-published.
[4] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Hydraulically Fractured Gas Well Completions and Workovers Estimate," available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-updates-1990-2013-inventory-published.
[5] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions to Natural Gas Transmission and Storage Emissions," available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2014-ghg.
[6] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions to Natural Gas and Petroleum Production Emissions," available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2014-ghg.
[7] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015: Revisions to Natural Gas and Petroleum Systems Production Emissions," available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg.
[8] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015: Revisions to Natural Gas Systems Processing Segment Emissions," available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg.

emissions for certain sources that relied on emission source-specific methods. The previous GHGI $CO_2$ EFs are documented in Appendix A.

## 1.1 $CO_2$-to-$CH_4$ Gas Content Ratio Methodology

The default GHGI methodology to calculate $CO_2$ emission factors (EFs) relies on $CH_4$ emission factors and an assumed ratio of $CO_2$-to-$CH_4$ gas content. The $CO_2$ EF calculation is shown in equation 1:

$$CO_2\ EF = CH_4\ EF * \left(\frac{CO_2\ content}{CH_4\ content}\right) \qquad \text{Equation 1}$$

The default $CH_4$ and $CO_2$ content values for sources in natural gas systems are from the 1996 GRI/EPA study,[9] EIA,[10] and GTI's Gas Resource Database[11] and summarized in Table 1 below.

**Table 1. Default Gas Content Values for Natural Gas Systems in the GHGI**

| Segment | $CH_4$ Content (vol%) | $CO_2$ Content (vol%) |
|---|---|---|
| Production – North East region | 78.8 | 3.04 |
| Production – Mid Central region | | 0.79 |
| Production – Gulf Coast region | | 2.17 |
| Production – South West region | | 3.81 |
| Production – Rocky Mountain region | | 7.58 |
| Production – West Coast region | | 0.16 |
| Processing – Before $CO_2$ removal | 87.0 | 3.45 |
| Processing – After $CO_2$ removal | | 1.0 |
| Transmission and Underground NG Storage | 93.4 | 1.0 |
| LNG Storage and LNG Import/Export | 93.4 | 1.16 |
| Distribution | 93.4 | 1.0 |

For most of the petroleum production sources evaluated in this memo, the GHGI uses a ratio of $CO_2$ to $CH_4$ content, set at 0.017 based on the average flash gas $CO_2$ and $CH_4$ content from API TankCalc runs.

The ratio of $CO_2$-to-$CH_4$ gas content methodology is used to calculate venting and fugitive $CO_2$ EFs, because the $CH_4$ EFs that are referenced for this methodology represent venting and fugitive emissions, which are predominantly $CH_4$ with minimal $CO_2$ emissions. EPA does not use this methodology in the GHGI to calculate $CO_2$ EFs for combustion sources such as flares, for which the inverse is true ($CO_2$ is predominant, with minimal $CH_4$ emissions).

## 1.2 Emission Source-Specific $CO_2$ Calculation Methodologies

The previous GHGI used the following emission source-specific methodologies to calculate $CO_2$ emissions from oil and condensate tanks at production sites, AGR units at natural gas processing plants, and production and processing flaring.

### 1.2.1 Oil and Condensate Tanks at Production Sites

The previous GHGI methodology to calculate $CO_2$ emissions for oil and condensate tanks used $CO_2$ specific EFs. The EFs were developed using API TankCalc software with varying API gravities. The oil tank EF is the average from

[9] Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary, Appendix A.
[10] U.S. Energy Information Administration. Emissions of Greenhouse Gases in the United States: 1987-1992, Appendix A. 1994.
[11] GRI-01/0136 GTI's Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases. Second Edition. August, 2001.

API TankCalc runs for oils with API gravity less than 45, and the condensate tank EF considered data with API gravity greater than 45. Condensate tank EFs were determined for both controlled and uncontrolled tanks; the controlled tank EF assumed a control efficiency of 80%. The previous GHGI calculated oil tank $CO_2$ emissions by applying the oil tank emission factor (EF) to 20% of stripper well production and 100% of non-stripper oil well production. For gas production, the previous GHGI methodology estimated tank emissions by applying the condensate tank EF to condensate production in each NEMS region.

### 1.2.2 AGR Units at Natural Gas Processing Plants

The previous GHGI $CO_2$ EF for AGR units at natural gas processing plants relied on gas $CO_2$ content only. The difference in the default $CO_2$ content before and after $CO_2$ removal (3.45% - 1.0% = 2.45% of processing plant gas throughput) is assumed to be emitted.

### 1.2.3 Flaring

Flaring emissions from the production and processing segments were previously calculated under a single line item in the production segment of natural gas systems. Therefore, flaring emissions were not specifically attributed to the natural gas systems processing segment or the petroleum systems production segment. The EF was based on data from EIA's 1996 greenhouse gas emissions inventory, which estimated the amount of $CO_2$ released per BTU of natural gas combusted (0.055 g/BTU). The activity data were annual EIA "Vented and Flared" gas volumes (MMcf), which are reported under Natural Gas Gross Withdrawals and Production,[12] combined with the estimated national average gas heating value (averaging approximately 1,100 BTU/cf over the time series[13]). The EIA Vented and Flared data represents a balancing factor amount that EIA calculates to reconcile reported upstream and downstream gas volumes, and assumes is potentially emitted to the atmosphere during production or processing operations; the previous GHGI methodology assumed it was all flared. Details on how much of the Vented and Flared gas is potentially emitted during natural gas production, petroleum production, and processing are not available, so the previous GHGI assigned it all to natural gas production. Also, the EIA data do not account for gas that is flared prior to metering.

Flaring emissions from the transmission and storage segment were not previously calculated in the GHGI. Flaring emissions from the distribution segment are not currently calculated in the GHGI. Data are unavailable on flaring emissions in the distribution segment, but they are likely to be insignificant based on the low prevalence of this activity in the industry segment. EPA did not consider revisions to the distribution segment $CO_2$ emissions calculation methodology for the 2018 GHGI.

## 2. Available Subpart W Data

Subpart W of the EPA's Greenhouse Gas Reporting Program (GHGRP) collects annual operating and emissions data on numerous sources from onshore natural gas and petroleum systems that meet a reporting threshold of 25,000 metric tons of $CO_2$ equivalent (mt $CO_2$e) emissions. Onshore production facilities in subpart W are defined as a unique combination of operator and basin of operation, a natural gas processing facility in subpart W is each unique processing plant, a natural gas transmission compression facility in subpart W is each unique transmission compressor station, an underground natural gas storage facility in subpart W is the collection of subsurface storage and processes and above ground wellheads, an LNG storage facility in subpart W is the collection of storage vessels and related equipment, and an LNG import and export facility in subpart W is the collection of equipment that handles LNG received from or transported via ocean transportation. Facilities in the above-mentioned industry segments that meet the subpart W reporting threshold have been reporting since 2011;

[12] EIA Natural Gas Gross Withdrawals and Production, including the Vented and Flared category, is available at https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_m.htm

[13] EIA Monthly Energy Review. Table A4 - Approximate Heat Content of Natural Gas (Btu per Cubic Feet).

currently, six years of subpart W reporting data are publicly available, covering reporting year (RY) 2011 through RY2016.[14]

Subpart W activity and emissions data have been used in recent GHGIs to calculate $CH_4$ emissions for several production, processing, and transmission and storage sources. $CO_2$ emissions data from subpart W had not yet been incorporated into the 2017 GHGI. However, facilities use an identical reporting structure for $CO_2$ and $CH_4$. Therefore, where subpart W $CH_4$ data have been used, the $CO_2$ data may be incorporated in a parallel manner. The 2014 HF Completion and Workover memo, 2016 Transmission memo, 2016 Production memo, 2017 Production memo, and 2017 Processing memo discuss in greater detail the subpart W data available for those sources.

EPA also reviewed subpart W data that could be used for $CO_2$ emission estimates from miscellaneous production flaring, acid gas removal (AGR) vents, and transmission and storage station flares—sources for which the emissions were not previously calculated with subpart W data in the GHGI.

Production segment flare emissions are only reported under the “flare stacks” emission source in subpart W if the flare emissions originate from sources not otherwise covered by subpart W—this emission source is referred to as “miscellaneous production flaring” for purposes of this memo. Therefore, the subpart W production flares data do not duplicate flaring emissions reported, for example, under production tank flaring or associated gas flaring. It also ensures all production flaring emissions are reported for facilities that meet the reporting threshold. Flare emissions are calculated using a continuous flow measurement device or engineering calculations, the gas composition, and the flare combustion efficiency. A default flare combustion efficiency of 98% may be applied, if manufacturer data are not available.

Under subpart W, gas processing facilities calculate AGR unit $CO_2$ emissions using one of four methods: (1) $CO_2$ CEMS; (2) a vent stream flow meter with $CO_2$ composition data; (3) calculation using an equation with the inlet or outlet natural gas flow rate and measured inlet and outlet $CO_2$ composition data; or (4) simulation software (e.g., AspenTech HYSYS or API 4679 AMINECalc). $CH_4$ emissions for AGR units are not reported in subpart W.

Transmission and underground natural gas storage stations report emissions from all flaring under the “flare stacks” emission source as of RY2015. Prior to that, flare emissions reported under subpart W were included in the reported emissions for the specific source (e.g., reciprocating or centrifugal compressor). Flare emissions are calculated in subpart W using a continuous flow measurement device or engineering calculations, the gas composition, and the flare combustion efficiency. A default flare combustion efficiency of 98% may be applied, if manufacturer data are not available.

# 3. 2018 GHGI Revisions

For the 2018 GHGI, EPA calculated $CO_2$ EFs using the same methodologies that were developed for $CH_4$ EFs in recent GHGIs. For associated gas venting and flaring and production segment miscellaneous flaring, while there was an existing methodology, EPA calculated both $CO_2$ and $CH_4$ emissions using a revised methodology for the 2018 GHGI. In addition, the EPA updated the GHGI to incorporate subpart W data for $CO_2$ from AGR units, and both the $CO_2$ emissions and the relatively minor $CH_4$ emissions from flare stacks in the production and transmission and storage segments.

[14] The GHGRP subpart W data used in the analyses discussed in this memo are those reported to the EPA as of August 5, 2017.

## 3.1 Production $CO_2$ Emission Factors

The EPA developed $CO_2$ EFs for several sources in the natural gas and petroleum production segments. The $CH_4$ EFs for oil and condensate tanks, pneumatic controllers, and pneumatic pumps were recently revised using subpart W data, and EPA applied the same methodology to calculate $CO_2$ EFs. There was an existing subpart W-based $CH_4$ methodology for associated gas venting and flaring and gas well hydraulically fractured completions and workovers, but a revised methodology was developed for these sources. The EPA also developed a $CO_2$ emissions calculation methodology for miscellaneous production flaring. Each of these sources are discussed below.

### 3.1.1 Associated Gas Venting and Flaring

The associated gas venting and flaring emissions calculation methodology was revised in the 2017 GHGI to use subpart W data and calculated $CH_4$ emissions using a national-level, well count-based scaling approach.[15] However, stakeholders commented that national-level EFs and AFs would not take into account differences in associated gas venting and flaring among geographic regions. In particular, over- or under-representation in GHGRP data by geographic regions where associated gas is vented or flared more or less frequently may disproportionately contribute to national-level factors. Stakeholders also commented that associated gas emissions are more directly related to production levels, rather than well counts. In response to stakeholder comments, the EPA reassessed the associated gas venting and flaring data and finalized a basin-level, production-based scaling approach for the 2018 GHGI. The final methodology is applied for both $CO_2$ and $CH_4$ emissions and is discussed here. The October 2017 version of this memo documents the national-level approach for $CO_2$ (following the 2017 GHGI methodology) and presents a NEMS region-level, well-based approach that was considered but not implemented.

The EPA first reviewed the reported subpart W associated gas venting and flaring emissions for RY2011 through RY2016 to identify basins that contribute the majority of the associated gas emissions. Specifically, if a basin contributed at least 10 percent of total annual emissions (on a $CO_2$ Eq. basis) from associated gas venting and flaring in any year, then basin-specific EFs and AFs were developed. See Appendix B for the associated gas emissions by year for all basins. Four basins met this criteria: 220 - Gulf Coast Basin (LA, TX); 360 - Anadarko Basin; 395 - Williston Basin; and 430 - Permian Basin. Associated gas venting and flaring data in all other basins were combined, and EFs and AFs developed for the other basins as a single group.

EPA calculated EFs for RY2015 and RY2016; subpart W data in earlier years do not contain publicly available production data. The EPA calculated $CO_2$ and $CH_4$ EFs for associated gas venting and flaring by summing the reported emissions for venting and flaring and dividing by the sum of the reported volume of oil produced during associated gas venting and flaring. Table 2 and Table 3 present the emissions and oil production data for years 2015 and 2016, and Table 4 shows the resulting EFs. The 2015 EFs were applied to all prior years in the time series.

**Table 2. Associated Gas Venting and Flaring Emissions and Oil Production, Subpart W RY2015**

| Basin | Venting $CO_2$ (mt) | Venting $CH_4$ (mt) | Volume of Oil Produced During Venting (bbl) | Flaring $CO_2$ (mt) | Flaring $CH_4$ (mt) | Volume of Oil Produced During Flaring (bbl) |
|---|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 93 | 1,259 | 2,110,981 | 589,431 | 2,718 | 18,591,586 |
| 360 - Anadarko Basin | 22 | 906 | 1,994,628 | 159,208 | 695 | 148,688 |
| 395 - Williston Basin | 151 | 1,564 | 229,586 | 7,890,206 | 23,965 | 264,426,732 |
| 430 - Permian Basin | 2,675 | 5,839 | 5,975,614 | 2,094,869 | 8,185 | 36,912,840 |
| All Other Basins | 8,520 | 6,303 | 2,522,412 | 390,300 | 1,749 | 27,110,014 |

[15] See the 2017 Production Memo for details.

**Table 3. Associated Gas Venting and Flaring Emissions and Oil Production, Subpart W RY2016**

| Basin | Venting $CO_2$ (mt) | Venting $CH_4$ (mt) | Volume of Oil Produced During Venting (bbl) | Flaring $CO_2$ (mt) | Flaring $CH_4$ (mt) | Volume of Oil Produced During Flaring (bbl) |
|---|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 267 | 2,089 | 1,250,441 | 298,967 | 1,187 | 13,547,580 |
| 360 - Anadarko Basin | 6 | 294 | 175,531 | 1,185 | 5 | 25,735 |
| 395 - Williston Basin | 140 | 1,356 | 234,720 | 5,035,977 | 14,017 | 208,727,344 |
| 430 - Permian Basin | 216 | 4,281 | 4,135,034 | 1,691,562 | 6,767 | 38,294,649 |
| All Other Basins | 4,538 | 4,353 | 6,711,810 | 284,496 | 1,049 | 18,628,782 |

**Table 4. Calculated Associated Gas Venting and Flaring Emission Factors (kg/bbl/yr)**

| Basin | Venting $CO_2$ EF | | Venting $CH_4$ EF | | Flaring $CO_2$ EF | | Flaring $CH_4$ EF | |
|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2015 | 2016 | 2015 | 2016 | 2015 | 2016 |
| 220 - Gulf Coast Basin (LA, TX) | 0.04 | 0.21 | 0.60 | 1.67 | 32 | 22 | 0.15 | 0.09 |
| 360 - Anadarko Basin | 0.01 | 0.03 | 0.45 | 1.68 | 1,071 | 46 | 4.7 | 0.20 |
| 395 - Williston Basin | 0.66 | 0.60 | 6.81 | 5.78 | 30 | 24 | 0.09 | 0.07 |
| 430 - Permian Basin | 0.45 | 0.05 | 0.98 | 1.04 | 57 | 44 | 0.22 | 0.18 |
| All Other Basins | 3.38 | 0.68 | 2.50 | 0.65 | 14 | 26 | 0.06 | 0.08 |

The EPA calculated two AFs for each basin or group: the percent of oil production with either flaring or venting of associated gas and, within that subset of production, the fraction that vents and the fraction that flares. The AFs were calculated for 2015 and 2016, and the 2015 activity factors applied to all prior years. The AF data are presented in Table 5 and Table 6.

**Table 5. Associated Gas Venting and Flaring Production Data and AFs, Subpart W RY2015**

| Basin | Volume of Oil Produced During Venting (bbl) | Volume of Oil Produced During Flaring (bbl) | Subpart W Liquids Production (bbl) | % Production with Flaring or Venting of Associated Gas | % Production with Venting | % Production with Flaring |
|---|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 2,110,981 | 18,591,586 | 650,435,832[a] | 3% | 10% | 90% |
| 360 - Anadarko Basin | 1,994,628 | 148,688 | 99,146,641 | 2.2% | 93% | 7% |
| 395 - Williston Basin | 229,586 | 264,426,732 | 447,415,171 | 59% | 0.1% | 99.9% |
| 430 - Permian Basin | 5,975,614 | 36,912,840 | 591,656,726 | 7% | 14% | 86% |
| All Other Basins | 2,522,412 | 27,110,014 | 645,262,423 | 5% | 9% | 91% |

a. Reported subpart W liquids production exceeded DrillingInfo production for basin, DrillingInfo production used to calculate AF.

**Table 6. Associated Gas Venting and Flaring Production Data and AFs, Subpart W RY2016**

| Basin | Volume of Oil Produced During Venting (bbl) | Volume of Oil Produced During Flaring (bbl) | Subpart W Liquids Production (bbl) | % Production with Flaring or Venting of Associated Gas | % Production with Venting | % Production with Flaring |
|---|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 1,250,441 | 13,547,580 | 516,246,773[a] | 3% | 8% | 92% |
| 360 - Anadarko Basin | 175,531 | 25,735 | 94,789,700 | 0.2% | 87% | 13% |
| 395 - Williston Basin | 234,720 | 208,727,344 | 322,617,029 | 65% | 0.1% | 99.9% |
| 430 - Permian Basin | 4,135,034 | 38,294,649 | 533,358,906 | 8% | 10% | 90% |
| All Other Basins | 6,711,810 | 18,628,782 | 1,464,067,958[a] | 2% | 26% | 74% |

a. Subpart W liquids production exceeded DrillingInfo production for basin, DrillingInfo production used to calculate AF.

EPA uses total liquids production data for each basin or group to calculate national emissions. Total liquids production data for each basin were determined from DrillingInfo, while the total national liquids production was available from EIA (consistent with current methodologies for other GHGI sources that rely on total national production data). Therefore, the national production for all other basins equals the EIA production minus the DrillingInfo production for each of the four basins. The total liquids production data for 2015 and 2016 are provided in Table 7, and the resulting national emissions are shown in Table 8.

**Table 7. Total Liquids Production (bbl), by Basin**

| Basin | Year 2015 | Year 2016 |
|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 650,435,832 | 516,246,773 |
| 360 - Anadarko Basin | 144,644,537 | 122,734,407 |
| 395 - Williston Basin | 456,423,760 | 396,753,744 |
| 430 - Permian Basin | 688,208,748 | 733,002,118 |
| All Other Basins | 1,494,207,123 | 1,464,067,958 |

**Table 8. Calculated Total Associated Gas Venting and Flaring Emissions**

| Basin | Venting $CO_2$ (mt) | | Venting $CH_4$ (mt) | | Flaring $CO_2$ (mt) | | Flaring $CH_4$ (mt) | |
|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2015 | 2016 | 2015 | 2016 | 2015 | 2016 |
| 220 - Gulf Coast Basin (LA, TX) | 93 | 267 | 1,259 | 2,089 | 589,431 | 298,967 | 2,718 | 1,187 |
| 360 - Anadarko Basin | 31 | 8 | 1,321 | 381 | 232,268 | 1,534 | 1,014 | 7 |
| 395 - Williston Basin | 154 | 173 | 1,596 | 1,668 | 8,049,073 | 6,193,234 | 24,447 | 17,238 |
| 430 - Permian Basin | 3,112 | 297 | 6,792 | 5,883 | 2,436,729 | 2,324,735 | 9,520 | 9,301 |
| All Other Basins | 19,728 | 4,538 | 14,596 | 4,353 | 903,802 | 284,496 | 4,049 | 1,049 |
| **Total** | **23,119** | **5,282** | **25,564** | **14,375** | **12,211,303** | **9,102,967** | **41,749** | **28,782** |

### 3.1.2 Miscellaneous Production Flaring

The EPA used subpart W RY2015 and RY2016 miscellaneous production flaring (reported under "flare stacks") emissions data to revise the GHGI and more fully account for flare emissions in the production segment. Subpart W data for this source were not previously considered. The EPA calculated the $CO_2$ and $CH_4$ EFs using a national-level, well count-based scaling approach for the 2018 GHGI public review draft; this methodology is documented in the previous July and October 2017 versions of this memo. However, similar to associated gas venting and flaring, stakeholders recommended a basin-level, production-based scaling approach. After evaluating the data, a basin-level, production-based scaling approach was applied for the 2018 GHGI, and is documented here.

The EPA reviewed the reported subpart W miscellaneous production flaring emissions for RY2011 through RY2016 to identify basins that contribute the majority of the associated gas emissions. Specifically, if a basin contributed at least 10 percent of total annual emissions (on a $CO_2$ Eq. basis) from miscellaneous production flaring in any year, then basin-specific emission factors and activity factors were developed. See Appendix C for the miscellaneous production flaring emissions by year for all basins. Three basins met this criteria: 220 - Gulf Coast Basin (LA, TX); 395 - Williston Basin; and 430 - Permian Basin. Miscellaneous production flaring data in all other basins were combined, and EFs and AFs developed for the other basins as a single group. EFs and AFs were developed using RY2015 and RY2016 data, as prior years do not contain publicly available production data.

Miscellaneous production flaring emissions are not reported separately for gas and oil production. Therefore, to use reported emissions data for separate natural gas and petroleum systems GHGI estimates, the EPA calculated the fraction of wells that were gas and oil wells for each facility, using the well counts reported in the Equipment Leaks section of subpart W.[16] The EPA then apportioned each facility's reported miscellaneous production flaring

[16] Three facilities with miscellaneous production flaring emissions did not report well counts. Therefore, for these three facilities, the EPA determined the fraction of sub-basins applicable to gas production (i.e., sub-basins with *high permeability gas*, *shale gas*, *coal seam,* or *other tight reservoir rock* formation types) and oil production (i.e., sub-basins with the *oil* formation type), and applied these fractions in the calculations.

$CO_2$ and $CH_4$ emissions by production type, and summed the facility-level $CO_2$ and $CH_4$ emissions for each production type to the basin-level to estimate total reported miscellaneous flaring $CO_2$ and $CH_4$ emissions from natural gas and oil production, for each basin or group.

Next, EPA used gas and liquids production data to develop EFs for calculating the national total emissions. The EPA calculated EFs by dividing the basin-level $CO_2$ and $CH_4$ emissions for natural gas and oil production by the summation of the reported gas produced from wells (for natural gas production EFs) and liquids produced (for oil production EFs). These emissions data, production data, and calculated EFs are provided in Table 9 through Table 12 below. The 2015 EFs were applied to all prior years in the time series.

**Table 9. GHGRP Subpart W RY2015 Natural Gas Production $CO_2$ and $CH_4$ Emissions and Activity Data and Calculated EFs for Miscellaneous Production Flaring**

| Basin | Gas $CO_2$ (mt) | Gas $CH_4$ (mt) | Gas Produced from Wells (mscf) | Gas $CO_2$ EF (kg/mscf/yr) | Gas $CH_4$ EF (kg/mscf/yr) |
|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 324,079 | 1,157 | 3,161,594,496 | 1.03E-01 | 3.66E-04 |
| 395 - Williston Basin | 56 | 0 | 645,705,949[a] | 8.61E-05 | 3.14E-07 |
| 430 - Permian Basin | 673,592 | 2,992 | 2,367,810,821[a] | 2.84E-01 | 1.26E-03 |
| All Other Basins | 310,453 | 1,337 | 20,352,492,312[a] | 1.53E-02 | 6.57E-05 |

a. Subpart W production exceeded DrillingInfo production for basin, DrillingInfo production used.

**Table 10. GHGRP Subpart W RY2015 Oil Production $CO_2$ and $CH_4$ Emissions and Activity Data and Calculated EFs for Miscellaneous Production Flaring**

| Basin | Oil $CO_2$ (mt) | Oil $CH_4$ (mt) | Liquids Produced (bbl) | Oil $CO_2$ EF (kg/bbl/yr) | Oil $CH_4$ EF (kg/bbl/yr) |
|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 859,858 | 3,548 | 652,726,411[a] | 1.32E+00 | 5.44E-03 |
| 395 - Williston Basin | 856,957 | 2,145 | 447,415,171 | 1.92E+00 | 4.79E-03 |
| 430 - Permian Basin | 424,156 | 1,626 | 591,656,726 | 7.17E-01 | 2.75E-03 |
| All Other Basins | 540,935 | 1,861 | 743,813,115[a] | 7.27E-01 | 2.50E-03 |

a. Subpart W production exceeded DrillingInfo production for basin, DrillingInfo production used.

**Table 11. GHGRP Subpart W RY2016 Natural Gas Production $CO_2$ and $CH_4$ Emissions and Activity Data and Calculated EFs for Miscellaneous Production Flaring**

| Basin | Gas $CO_2$ (mt) | Gas $CH_4$ (mt) | Gas Produced from Wells (mscf) | Gas $CO_2$ EF (kg/mscf/yr) | Gas $CH_4$ EF (kg/mscf/yr) |
|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 213,698 | 584 | 2,661,846,306 | 8.03E-05 | 2.19E-07 |
| 395 - Williston Basin | 206 | 0 | 649,228,154[a] | 3.18E-07 | 5.28E-10 |
| 430 - Permian Basin | 438,567 | 1,939 | 2,356,640,169 | 1.86E-04 | 8.23E-07 |
| All Other Basins | 339,247 | 1,573 | 19,553,610,690[a] | 1.73E-05 | 8.05E-08 |

a. Subpart W production exceeded DrillingInfo production for basin, DrillingInfo production used.

**Table 12. GHGRP Subpart W RY2016 Oil Production $CO_2$ and $CH_4$ Emissions and Activity Data and Calculated EFs for Miscellaneous Production Flaring**

| Basin | Oil $CO_2$ (mt) | Oil $CH_4$ (mt) | Liquids Produced (bbl) | Oil $CO_2$ EF (kg/bbl/yr) | Oil $CH_4$ EF (kg/bbl/yr) |
|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 389,281 | 1,630 | 518,218,649[a] | 7.51E-04 | 3.15E-06 |
| 395 - Williston Basin | 274,154 | 778 | 322,617,029 | 8.50E-04 | 2.41E-06 |
| 430 - Permian Basin | 563,672 | 1,991 | 533,358,906 | 1.06E-03 | 3.73E-06 |
| All Other Basins | 414,762 | 1,035 | 689,536,735[a] | 6.02E-04 | 1.50E-06 |

a. Subpart W production exceeded DrillingInfo production for basin, DrillingInfo production used.

EPA calculated national emissions using the appropriate national production (i.e., total gas production or liquids production) for each basin or group. Total gas production data for each basin and for the nation were determined from DrillingInfo. Total liquids production data for each basin were determined from DrillingInfo, while the total national liquids production was available from EIA (consistent with current methodologies for other GHGI sources that rely on total national production data). Therefore, the national liquids production for all other basins equals the EIA production, minus the DrillingInfo production for each of the three basins. The production data and resulting national emissions for 2015 and 2016 are shown in Table 13 and Table 14.

**Table 13. Total Production Data and Miscellaneous Production Flaring Emissions for Natural Gas and Petroleum Systems, Reporting Year 2015**

| Basin | Total Gas Production (mscf) | Total Liquids Production (bbl) | Gas $CO_2$ (mt) | Gas $CH_4$ (mt) | Oil $CO_2$ (mt) | Oil $CH_4$ (mt) |
|---|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 3,519,664,923 | 652,726,411 | 360,782 | 1,288 | 859,858 | 3,548 |
| 395 - Williston Basin | 645,705,949 | 456,442,746 | 56 | 0 | 874,248 | 2,188 |
| 430 - Permian Basin | 2,367,810,821 | 688,752,179 | 673,592 | 2,992 | 493,763 | 1,893 |
| All Other Basins | 24,940,124,177 | 1,635,998,664 | 380,431 | 1,639 | 1,189,773 | 4,094 |
| **Total** | **31,473,305,870** | **3,433,920,000** | **1,414,861** | **5,918** | **3,417,643** | **11,724** |

**Table 14. Total Production Data and Miscellaneous Production Flaring Emissions for Natural Gas and Petroleum Systems, Reporting Year 2016**

| Basin | Total Gas Production (mscf) | Total Liquids Production (bbl) | Gas CO2 (mt) | Gas CH4 (mt) | Oil CO2 (mt) | Oil CH4 (mt) |
|---|---|---|---|---|---|---|
| 220 - Gulf Coast Basin (LA, TX) | 3,061,920,423 | 518,218,649 | 245,817 | 672 | 389,281 | 1,630 |
| 395 - Williston Basin | 649,228,154 | 396,772,982 | 206 | 0 | 337,170 | 957 |
| 430 - Permian Basin | 2,546,961,000 | 733,544,659 | 473,985 | 2,095 | 775,235 | 2,738 |
| All Other Basins | 23,551,484,913 | 1,584,268,710 | 408,609 | 1,895 | 952,951 | 2,378 |
| **Total** | **29,809,594,491** | **3,232,805,000** | **1,128,617** | **4,662** | **2,454,637** | **7,703** |

### 3.1.2 Production Tanks

Based on the $CH_4$ EF methodology documented in the 2017 Production memo, the EPA calculated oil and condensate tank $CO_2$ EFs for several tank categories, using subpart W data: large tanks with flaring; large tanks with a vapor recovery unit (VRU); large tanks without controls; small tanks with flaring; small tanks without flaring; and malfunctioning separator dump valves. EPA applied several steps described in the 2017 Production memo to apportion the reported subpart W data to each of the categories. EPA then summed the emissions and divided by the throughput for each tank category. Table 15 presents the resulting $CO_2$ EFs for RY2015 (which are applied for 2015 and all prior years in the time series) and RY2016.

**Table 15. GHGRP Subpart W-based Oil and Condensate Tank $CO_2$ EFs (kg/bbl/yr)**

| Tank Category | Oil Tanks EF | | Condensate Tanks EF | |
|---|---|---|---|---|
| | 2015 | 2016 | 2015 | 2016 |
| Large Tanks with Flaring | 7.21 | 6.98 | 8.33 | 10.90 |
| Large Tanks with VRU | 0.037 | 0.025 | 0.11 | 0.12 |
| Large Tanks without Controls | 0.016 | 0.019 | 0.019 | 0.026 |
| Small Tanks with Flaring | 0.27 | 1.64 | 1.96 | 4.46 |
| Small Tanks without Flares | 0.078 | 0.066 | 0.28 | 0.46 |
| Malfunctioning Dump Valves | 0.013 | 0.012 | 8.19E-05 | 6.98E-05 |

### 3.1.4 Pneumatic Controllers

Based on the $CH_4$ EF methodology documented in the 2016 Production memo, the EPA calculated pneumatic controller $CO_2$ EFs for low, intermittent, and high bleed controllers using Subpart W RY2014 data. EPA divided the reported emissions by the number of reported controllers for each controller type to calculate EFs. All pneumatic controllers data were considered together, and thus pneumatic controller EFs for natural gas and petroleum systems are identical. Table 16 presents the subpart W activity and emissions data, along with the calculated $CO_2$ EFs.

**Table 16. GHGRP Subpart W RY2014 Activity and Emissions Data and Calculated EFs for Pneumatic Controllers**

| Controller Type | # Controllers | Total $CO_2$ Emissions (mt) | $CO_2$ EF (kg/controller/yr) |
|---|---|---|---|
| Low Bleed | 198,941 | 2,382 | **12** |
| Intermittent Bleed | 561,283 | 98,269 | **175** |
| High Bleed | 27,208 | 9,790 | **360** |

### 3.1.5 Pneumatic Pumps

Based on the $CH_4$ EF methodology documented in the 2016 Production memo, the EPA calculated a pneumatic pump $CO_2$ EF using Subpart W RY2014 data. EPA divided the reported emissions by the number of reported pneumatic pumps to calculate the EF. All pneumatic pumps data were considered together, and thus the EF for natural gas and petroleum systems is identical. Table 17 presents the subpart W activity and emissions data, along with the calculated $CO_2$ EF.

**Table 17. GHGRP Subpart W RY2014 Activity and Emissions Data and Calculated EF for Pneumatic Pumps**

| # Pumps | Total $CO_2$ Emissions (mt) | $CO_2$ EF (kg/pump/yr) |
|---|---|---|
| 79,760 | 11,647 | **146** |

### 3.1.3 HF Gas Well Completions and Workovers

EPA calculated $CO_2$ emissions for the 2018 GHGI public review draft using the $CH_4$ EF methodology documented in the 2014 HF Completion and Workover memo and 2015 HF Completion and Workover memo. See the earlier versions of this memo from June and October 2017 for the resulting EFs. However, both the $CO_2$ and $CH_4$ calculation methodologies for this source were revised for the final 2018 GHGI, and these revisions are documented in the *2018 Year-Specific Emissions memo*.[17]

### 3.1.6 Liquids Unloading

EPA calculated $CO_2$ emissions for the 2018 GHGI public review draft using the $CH_4$ EF methodology documented in the 2017 Production memo. See the earlier versions of this memo from June and October 2017 for the resulting EFs. However, both the $CO_2$ and $CH_4$ calculation methodologies for this source were revised for the final 2018 GHGI, and these revisions are documented in the *2018 Year-Specific Emissions memo*.

## 3.2 Processing $CO_2$ Emission Factors

The EPA developed gas processing $CO_2$ EFs for the plant grouped emission sources (reciprocating compressors, centrifugal compressors with wet seals, centrifugal compressors with dry seals, dehydrators, flares, and plant fugitives), blowdowns and venting, and AGR vents. The $CH_4$ EFs for the grouped sources and blowdowns and venting were recently revised using subpart W data, and the EPA applied the same methodology to calculate $CO_2$ EFs. AGR vent emissions were not previously calculated from subpart W data (as $CH_4$ emissions are not reported for this source), but the EPA calculated a subpart W-based $CO_2$ EF and determined the corresponding activity data for this source.

[17] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Revisions to Create Year-Specific Emissions and Activity Factors," available online at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2016-ghg.

Based on the $CH_4$ EF methodology documented in the 2017 Processing memo, the EPA calculated the plant grouped source $CO_2$ EFs using subpart W data (the purpose of the plant grouped EF is discussed in Section 3.4). Subpart W RY2015 and RY2016 data and calculated $CO_2$ EFs for the plant grouped sources are presented in Table 18 and Table 19.

**Table 18. GHGRP Subpart W RY2015 Emissions and Activity Data and Calculated EFs for Gas Processing Plant Grouped Sources**

| Emission Source | $CO_2$ Emissions (mt) | Activity Count (plants or compressors) | | $CO_2$ EF (kg/compressor/yr or kg/plant/yr) |
|---|---|---|---|---|
| Reciprocating compressors | 7,618 | 2,678 | compressors | 2,845 |
| Centrifugal compressors with wet seals | 1,259 | 264 | compressors | 4,768 |
| Centrifugal compressors with dry seals | 21 | 215 | compressors | 400 |
| Dehydrators | 7,430 | 466 | plants | 15,944 |
| Flares | 4,231,009 | 466 | plants | 9,079,418 |
| Plant fugitives | 2,244 | 466 | plants | 4,816 |
| **Plant Grouped Sources** | **4,249,580** | **466** | **plants** | **9,119,411** |

**Table 19. GHGRP Subpart W RY2016 Emissions and Activity Data and Calculated EFs for Gas Processing Plant Grouped Sources**

| Emission Source | $CO_2$ Emissions (mt) | Activity Count (plants or compressors) | | $CO_2$ EF (kg/compressor/yr or kg/plant/yr) |
|---|---|---|---|---|
| Reciprocating compressors | 7,275 | 2,737 | compressors | 2,658 |
| Centrifugal compressors with wet seals | 839 | 226 | compressors | 3,711 |
| Centrifugal compressors with dry seals | 39 | 228 | compressors | 474 |
| Dehydrators | 4,467 | 447 | plants | 9,994 |
| Flares | 3,621,791 | 447 | plants | 8,102,440 |
| Plant fugitives | 2,599 | 447 | plants | 5,813 |
| **Plant Grouped Sources** | **3,637,009** | **447** | **plants** | **8,136,640** |

Based on the $CH_4$ EF methodology documented in the 2017 Processing memo, the EPA also calculated the blowdown and venting $CO_2$ EF using subpart W data. Subpart W RY2015 data and the calculated $CO_2$ EF for blowdowns and venting are presented in Table 20.

**Table 20. GHGRP Subpart W RY2015 Emissions and Activity Data and Calculated EF for Gas Processing Blowdown and Venting**

| RY | CO2 Emissions (mt) | Activity Count (plants) | $CO_2$ EF (kg/plant/yr) |
|---|---|---|---|
| 2015 | 11,059 | 466 | **23,731** |
| 2016 | 7,817 | 447 | **17,487** |

For AGR vent emissions, the existing $CH_4$ EF methodology does not rely on subpart W, but the EPA applied a similar methodology as the other processing sources to develop $CO_2$ EFs and activity data from subpart W data. The EPA summed the reported AGR vent $CO_2$ emissions for gas processing plants and divided by the total reported count of plants for each RY to calculate $CO_2$ EFs. Subpart W RY2015 and RY2016 data and the calculated $CO_2$ EFs for AGR vents are presented in Table 21. To calculate national $CO_2$ emissions, the $CO_2$ EF was multiplied by the number of gas plants each year.

**Table 21. GHGRP Subpart W Emissions and Activity Data and Calculated EFs for Gas Processing AGR Vents**

| Year | $CO_2$ Emissions (mt) | Activity Count (plants) | $CO_2$ EF (kg/plant/yr) |
|---|---|---|---|
| 2015 | 10,441,754 | 466 | **22,407,197** |
| 2016 | 11,101,161 | 447 | **24,834,813** |

## 3.3 Transmission and Storage $CO_2$ Emission Factors

### 3.3.1 Pneumatic Controllers

Based on the $CH_4$ EF methodology documented in the 2016 Transmission memo, the EPA calculated transmission station and storage station pneumatic controller $CO_2$ EFs for low, intermittent, and high bleed controllers using Subpart W RY2011 - RY2016 data. The EPA divided the reported emissions by the number of reported controllers for each controller type to calculate EFs. Table 22 and Table 23 present the subpart W activity and emissions data, along with the calculated $CO_2$ EFs. The RY2011 EFs were applied for all prior years in the time series.

**Table 22. GHGRP Subpart W Activity and Emissions Data and Calculated EFs for Transmission Station Pneumatic Controllers**

| Controller Type | Data Element | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| High Bleed | Total Count | 2,203 | 1,114 | 1,158 | 1,173 | 1,508 | 1,000 |
| | $CO_2$ Emissions (mt) | 203 | 106 | 106 | 107 | 121 | 85 |
| | **$CO_2$ EF (kg/controller/yr)** | **92** | **95** | **91** | **91** | **80** | **85** |
| Intermittent Bleed | Total Count | 8,343 | 9,114 | 9,903 | 11,160 | 10,891 | 11,122 |
| | $CO_2$ Emissions (mt) | 673 | 736 | 747 | 134 | 105 | 120 |
| | **$CO_2$ EF (kg/controller/yr)** | **81** | **81** | **75** | **12** | **10** | **11** |
| Low Bleed | Total Count | 644 | 880 | 857 | 1,078 | 1,033 | 943 |
| | $CO_2$ Emissions (mt) | 4.6 | 6.2 | 6.2 | 6.7 | 4.3 | 4.5 |
| | **$CO_2$ EF (kg/controller/yr)** | **7.1** | **7.0** | **7.3** | **6.2** | **4.2** | **4.8** |

**Table 23. GHGRP Subpart W Activity and Emissions Data and Calculated EFs for Underground Natural Gas Storage Station Pneumatic Controllers**

| Controller Type | Data Element | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| High Bleed | Total Count | 1,253 | 1,100 | 1,089 | 1,271 | 1,024 | 1,051 |
| | $CO_2$ Emissions (mt) | 116 | 118 | 116 | 117 | 64 | 97 |
| | **$CO_2$ EF (kg/controller/yr)** | **92** | **107** | **106** | **92** | **63** | **92** |
| Intermittent Bleed | Total Count | 1,391 | 1,539 | 1,601 | 2,045 | 2,098 | 2,288 |
| | $CO_2$ Emissions (mt) | 16 | 21 | 21 | 24 | 22 | 50 |
| | **$CO_2$ EF (kg/controller/yr)** | **12** | **13** | **13** | **12** | **10** | **22** |
| Low Bleed | Total Count | 250 | 319 | 366 | 319 | 320 | 289 |
| | $CO_2$ Emissions (mt) | 1.9 | 2.4 | 2.8 | 2.2 | 1.4 | 1.6 |
| | **$CO_2$ EF (kg/controller/yr)** | **7.5** | **7.4** | **7.6** | **7.0** | **4.4** | **5.5** |

### 3.3.2 Flares

The EPA developed GHGI flare $CO_2$ EFs for transmission stations and underground natural gas storage using subpart W data. As discussed in Section 1.3, the GHGI $CO_2$ emissions calculation methodology did not previously calculate $CO_2$ emissions from flares. Therefore, the EPA updated the methodology to calculate $CO_2$ emissions with new line items for transmission and storage flares.

The EPA divided the reported flare $CO_2$ and $CH_4$ emissions by the number of reported stations to calculate the EFs. Subpart W transmission station and underground natural gas storage flare data are presented in Table 24 and Table 25. The applicable activity data to calculate national emissions are the national number of stations, which are already calculated in the GHGI. The RY2015 EFs were applied for all prior years in the time series.

Note these flaring emissions estimates were developed from reported GHGRP data, wherein transmission compressor stations that service underground storage fields might be classified as transmission compression as the primary function. Therefore, a fraction of the transmission station flaring emissions may occur at stations that service storage facilities; such stations typically require flares, compared to a typical transmission compressor station used solely for mainline compression that does not require liquids separation, dehydration, and flaring.

**Table 24. GHGRP Subpart W RY2015 Emissions and Activity Data and Calculated EFs for Transmission Station Flares**

| Year | Total # Stations | # Stations With Flares | # Flares | Total $CO_2$ Emissions (mt) | $CO_2$ EF (kg/station/yr) | Total $CH_4$ Emissions (mt) | $CH_4$ EF (kg/station/yr) |
|---|---|---|---|---|---|---|---|
| 2015 | 524 | 18 | 30 | 23,833 | 45,483 | 93 | 177 |
| 2016 | 529 | 17 | 26 | 25,116 | 47,479 | 112 | 212 |

**Table 25. GHGRP Subpart W RY2015 Emissions and Activity Data and Calculated EFs for Underground Natural Gas Storage Flares**

| Year | Total # Stations | # Stations With Flares | # Flares | Total $CO_2$ Emissions (mt) | $CO_2$ EF (kg/station/yr) | Total $CH_4$ Emissions (mt) | $CH_4$ EF (kg/station/yr) |
|---|---|---|---|---|---|---|---|
| 2015 | 53 | 9 | 23 | 3,587 | 67,676 | 35 | 651 |
| 2016 | 53 | 9 | 21 | 2,343 | 44,214 | 30 | 572 |

## 3.4 Time Series Considerations

For the production segment sources discussed in Section 3.1, in general, the EPA applied the same methodology to calculate $CO_2$ over the time series as used for calculating $CH_4$ emissions over the time series.[18] For oil and condensate tanks, the EPA applies category-specific EFs for every year of the time series and for pneumatic controllers and pumps, category-specific EFs are applied for each year of the time series.

For associated gas venting and flaring, for $CH_4$, the EPA applied the subpart W 2015 EFs for years prior to 2015 and year-specific subpart W EFs were applied for 2015 and forward.

For the miscellaneous production flaring time series, the previous GHGI flare emission estimate (representing both production and processing), fluctuated based on activity data (EIA's estimated annual vented and flared volumes). Assessment of subpart W $CO_2$ data over the time series for this source indicates that miscellaneous production flaring emissions do not show a clear trend. See the Requests for Stakeholder Feedback section for more information. In the revised approach to use subpart W-based EFs (kg/mscf or kg/bbl), the EF was held constant for years prior to 2015 and flare emission estimates fluctuated with gas and liquids production data over the time series.

For certain processing sources discussed in Section 3.2, the EPA applied the same methodology to calculate $CO_2$ over the time series as used for calculating $CH_4$ emissions over the time series.[19] For plant grouped emission sources and blowdowns and venting, GRI/EPA 1996 EFs are used for 1990 through 1992; EFs calculated from subpart W are used for 2011 forward; and EFs for 1993 through 2010 are developed through linear interpolation.

[18] Additional details on current time series calculations for production segment sources are provided in the 2014 HF Completion and Workover memo, 2015 HF Completion and Workover memo, 2016 Production memo, and 2017 Production memo.

[19] Additional details on current time series calculations are provided in the 2017 Processing memo.

For $CO_2$ from AGR vents, the EPA adopted a similar methodology as the other processing sources (maintain the current GRI/EPA 1996 EFs for 1990 through 1992, apply the subpart W-based EFs for 2011 forward, and develop EFs for 1993 through 2010 using linear interpolation).

For transmission and storage flares, the EPA applied the 2015 subpart W-based EF (kg/station) for all prior years of the time series and year-specific EFs for 2015 and forward.

## 4. National Emissions Estimates

For sources with the largest contribution to $CO_2$ emissions (e.g., flaring sources), national $CO_2$ emissions for year 2015 using the subpart W-based approaches discussed in Section 3 (and implemented in the 2018 GHGI) are compared against the 2017 GHGI in Table 26 and Table 27.

**Table 26. Natural Gas Systems Year 2015 National $CO_2$ Emissions (MMT) for 2018 GHGI Compared to 2017 GHGI**

| Industry Segment and Emission Source | 2017 GHGI (Year 2015) | 2018 GHGI (Year 2015) |
|---|---|---|
| ***Exploration*** | ***NA*** | ***0.29*** |
| HF Completions | 0.07 | 0.28 |
| ***Production*** | ***17.6*** | ***3.40*** |
| Miscellaneous Flaring | 17.6[a] | 1.41 |
| Tanks | 0.03 | 1.09 |
| HF Workovers | 0.03 | 0.08 |
| ***Processing*** | ***23.7*** | ***21.04*** |
| AGR Vents | 23.6 | 14.95 |
| Plant Grouped Sources | 0.1 | 6.08 |
| ***Transmission & Storage*** | ***0*** | ***0.15*** |
| Transmission Flares | 0 | 0.11 |
| Underground Storage Flares | 0 | 0.02 |
| ***Distribution*** | ***0*** | ***0.01*** |
| **Natural Gas Systems Total** | **42.4** | **24.9** |

NA (Not Applicable)

a. Also represents flaring from petroleum production and gas processing.

**Table 27. Petroleum Systems Year 2015 National $CO_2$ Emissions (MMT) for 2018 GHGI Compared to 2017 GHGI**

| Industry Segment and Emission Source | 2017 GHGI (Year 2015) | 2018 GHGI (Year 2015) |
|---|---|---|
| ***Exploration*** | ***NA*** | ***0.26*** |
| Well Testing | NE | 0.26 |
| ***Production*** | ***0.64*** | ***24.48*** |
| Associated Gas | NE | 12.23 |
| Tanks | 0.52 | 8.72 |
| Miscellaneous Flaring | NE[a] | 3.42 |
| ***Transportation*** | ***NE*** | ***NE*** |
| ***Refining*** | ***2.93*** | ***4.01*** |
| **Petroleum Systems Total** | **3.57** | **28.75** |

NA (Not Applicable)

NE (Not Estimated)

a. In the 2017 GHGI, emissions were generally included within the natural gas systems production flaring estimate.

The $CO_2$ revisions resulted in an overall shift of $CO_2$ emissions from Natural Gas systems to Petroleum systems. This is due to the availability of industry segment-specific and emission source-specific data in subpart W, whereas previous data sources were not as granular. The previous GHGI accounted for all onshore production and gas processing flaring emissions under a single line item in the production segment of natural gas systems. Using the revised approaches, flaring emissions are now specifically calculated for natural gas production, petroleum production, and gas processing (within the plant grouped emission sources). The shift in $CO_2$ emissions from Natural Gas systems to Petroleum systems is also due to the inclusion of associated gas flaring as a specific line item under Petroleum systems; this is the largest source of $CO_2$ emissions for the revisions.

# 5. October 2017 Requests for Stakeholder Feedback

The EPA initially sought feedback on the questions below in the version of this memo released in October 2017. The questions below were minimally altered to specifically cite the October 2017 memo. The EPA discusses feedback received, and further planned improvements to the GHGI methodology, in Chapter 3.8 of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016* (April 2018). The EPA continues to welcome additional stakeholder feedback on these questions for potential updates to future GHGIs.

**General**

1. EPA seeks stakeholder feedback on the general approach of using subpart W reported $CO_2$ emissions data to revise the current $CO_2$ emissions calculation methodology (described in Section 1) in the GHGI.

2. EPA seeks feedback on using consistent calculation methodologies for both $CH_4$ and $CO_2$, when GHGI relies on subpart W data. Are there sources where the $CH_4$ and $CO_2$ methodologies based on subpart W should differ?

**Associated Gas Venting and Flaring (Section 3.1.1)**

3. EPA seeks feedback on the methodology to calculate national emissions from associated gas venting and flaring. In particular, which methodology discussed in Section 3.1.1 of the October 2017 memo (national-level, or NEMS region-level) or other approach best reflects national-level emissions from associated gas venting and flaring by taking into account variability of this source?

4. What scale-up assumptions should EPA make regarding associated gas venting or flaring for regions that do not report any oil well data to GHGRP? Should EPA assume that these regions have no such activity, or should EPA assign surrogate EF and AF values (e.g., average from all other reported regions, or some other methodology)?

5. Should EPA consider an approach not presented in Section 3.1.1 of the October 2017 memo?
    a. For example, scaling subpart W-based estimates using production rather than oil well counts?
    b. For example, disaggregating to the AAPG basin-level?

**GHGI Sources that Are Not Currently Estimated Using Subpart W data**

6. In the October 2017 memo, Section 3.1.7 discusses considerations for developing EFs and associated activity data for miscellaneous production flaring that facilitate scaling reported subpart W data to a national level. The EPA has presented a preliminary approach that develops an EF in units of emissions per well. National active well counts would be paired with such EF to calculate emissions in the GHGI. The EPA seeks feedback on this approach, or suggestions of other approaches that would facilitate scaling to a national level and time series population.

7. For sources discussed in the October 2017 memo that do not currently estimate $CH_4$ emissions using subpart W, EPA is considering which year(s) of subpart W data to use in developing the $CO_2$ emissions methodologies. For miscellaneous production flaring, the EPA reviewed reported emissions and activity data for RY2011 - RY2014. However, wellhead counts for RY2011 - RY2014 are only reported by those facilities that calculated equipment leak emissions using Methodology 1, and as such, are not comprehensive. At the time of the 2016 Production memo, 83% of reporting facilities for RY2011, 85% of RY2012 reporting facilities, 93% of RY2013 facilities, and 98% of RY2014 reporting facilities reported wellhead counts under Methodology 1. In addition, facilities only reported total wellheads and did not report gas and oil wellhead counts separately for RY2011 - RY2014. The EPA calculated the $CO_2$ EFs under consideration using RY2015 only, because well counts from all reporting facilities are reported. However, the EPA requests feedback on whether it is appropriate to consider data from prior reporting years, which would have more uncertainty due to incomplete coverage, in order to show a trend over the time series. Table 28 provides the reported subpart W emissions and activity data for RY2011-RY2015.

**Table 28. GHGRP Subpart W Emissions and Activity Data for Miscellaneous Production Flaring**

| Year | $CO_2$ Emissions (mt) | # Flares | # Wells (a) | $CO_2$ EF (kg/well) |
|---|---|---|---|---|
| 2011 | 2,252,297 | 13,509 | 371,604 | 6,061 |
| 2012 | 3,616,326 | 16,356 | 398,137 | 9,083 |
| 2013 | 4,596,329 | 21,098 | 415,355 | 11,066 |
| 2014 | 4,841,116 | 22,155 | 502,391 | 9,636 |
| 2015 | 3,779,110 | 20,293 | 527,170 | 7,169 |

a. Total gas and oil wellheads. Wellhead counts for RY2011 through RY2014 are available from those onshore production facilities that calculated equipment leak emissions using Methodology 1.

For transmission and storage segment flares, the EPA relies on RY2015 data for the revisions under consideration, because all flaring emissions are reported under the flare stacks source. Whereas, for RY2011 - RY2014, flare emissions are reported under flare stacks and each individual emission source.

8. Section 3.4 in the October 2017 memo discusses time series considerations for transmission and storage flares. The EPA is considering applying a subpart W-based EF (kg/station) for all years of the time series. However, few transmission and storage stations reported flares for RY2015 (see Table 24 and Table 25). Therefore, EPA might alternatively assume that flares did not operate in 1990 (i.e., an EF of 0), apply the subpart W-based EF for 2011 forward, and apply linear interpolation from 1991 through 2010. The EPA seeks feedback on these approaches, or suggestions of other approaches to time series population.

# Appendix A – Current (2017) GHGI $CO_2$ Emission Factors

All EFs are presented in the same units as the EFs under consideration for the 2018 GHGI; kg/[unit].

| Emission Source | GHGI $CO_2$ EF | EF Units |
|---|---|---|
| **Natural Gas & Petroleum Production** | | |
| Stripper Wells (for Associated Gas Venting) | 2.47 | kg/well |
| Condensate Tank Vents - Without Control Devices | 0.18 | kg/bbl |
| Condensate Tank Vents - With Control Devices | 0.037 | kg/bbl |
| Oil Tanks | 0.18 | kg/bbl |
| HF Gas Well Completions and Workovers | 18,367[a] | kg/event |
| Pneumatic Controllers, all bleed types (Natural Gas) | 144[a] | kg/controller |
| Low Bleed Pneumatic Controllers (Petroleum) | 8.8 | kg/controller |
| Intermittent Bleed Pneumatic Controllers (Petroleum) | 83.9 | kg/controller |
| High Bleed Pneumatic Controllers (Petroleum) | 238.9 | kg/controller |
| Pneumatic Pumps (Natural Gas) | 168.4[a] | kg/pump |
| Pneumatic Pumps (Petroleum) | 82.8 | kg/pump |
| Liquids Unloading with Plunger Lifts | 613[a] | kg/well |
| Liquids Unloading without Plunger Lifts | 678[a] | kg/well |
| Onshore Production & Processing - Flaring Emissions | 40,624 | kg/well |
| **Natural Gas Processing** | | |
| Reciprocating compressors - before CO2 removal | 4,764 | kg/compressor |
| Reciprocating compressors - after CO2 removal | 1,058 | kg/compressor |
| Centrifugal compressors with wet seals - before CO2 removal | 21,859 | kg/compressor |
| Centrifugal compressors with wet seals - after CO2 removal | 4,854 | kg/compressor |
| Centrifugal compressors with dry seals - before CO2 removal | 10,719 | kg/compressor |
| Centrifugal compressors with dry seals - after CO2 removal | 2,380 | kg/compressor |
| Plant fugitives - before CO2 removal | 3,364 | kg/plant |
| Plant fugitives - after CO2 removal | 747 | kg/plant |
| Kimray pumps | 859 | kg/plant |
| Dehydrator vents | 5,291 | kg/plant |
| **Plant Grouped Sources** | **95,303** | **kg/plant** |
| AGR vents | 35,394,396 | kg/plant |
| Blowdowns and venting | 8,363 | kg/plant |
| **Transmission** | | |
| High Bleed Pneumatic Controllers | 84.43 | kg/controller |
| Intermittent Bleed Pneumatic Controllers | 10.95 | kg/controller |
| Low Bleed Pneumatic Controllers | 6.22 | kg/controller |
| **Underground NG Storage** | | |
| High Bleed Pneumatic Controllers | 82.21 | kg/controller |
| Intermittent Bleed Pneumatic Controllers | 10.74 | kg/controller |
| Low Bleed Pneumatic Controllers | 6.34 | kg/controller |

a. Average EF based on data from all NEMS regions.

# Appendix B – GHGRP Subpart W Associated Gas Venting and Flaring Emissions, by basin, for RY2011-2016

| Basin | 2011 | | 2012 | | 2013 | | 2014 | | 2015 | | 2016 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total $CO_2$ + $CH_4$ Emissions (mt $CO_2$e) | % of Total | Total $CO_2$ + $CH_4$ Emissions (mt $CO_2$e) | % of Total | Total $CO_2$ + $CH_4$ Emissions (mt $CO_2$e) | % of Total | Total $CO_2$ + $CH_4$ Emissions (mt $CO_2$e) | % of Total | Total $CO_2$ + $CH_4$ Emissions (mt $CO_2$e) | % of Total | Total $CO_2$ + $CH_4$ Emissions (mt $CO_2$e) | % of Total |
| 160 - Appalachian Basin | 256 | 0% | 267 | 0% | 272 | 0% | 208 | 0% | 183 | 0% | 6,061 | 0% |
| 160A - Appalachian Basin (Eastern Overthrust Area) | 16,224 | 0% | 23,477 | 0% | 27,119 | 0% | 15,055 | 0% | 36,404 | 0% | 18,016 | 0% |
| 210 - Mid-Gulf Coast Basin | 22,825 | 0% | 14,535 | 0% | 32,584 | 0% | 68,569 | 1% | 95,521 | 1% | 103,081 | 1% |
| 220 - Gulf Coast Basin (LA, TX) | 773,401 | 10% | 944,157 | 9% | 1,411,635 | 12% | 990,875 | 8% | 688,957 | 6% | 381,131 | 5% |
| 230 - Arkla Basin | 5,306 | 0% | 3,354 | 0% | 3,552 | 0% | 3,551 | 0% | 17,847 | 0% | 12,171 | 0% |
| 260 - East Texas Basin | 2,434 | 0% | 325,252 | 3% | 48,131 | 0% | 130 | 0% | 1,134 | 0% | 3,560 | 0% |
| 305 - Michigan Basin | 103,228 | 1% | 159,425 | 2% | 130,168 | 1% | 124,802 | 1% | 101,424 | 1% | 73,317 | 1% |
| 345 - Arkoma Basin | 18,059 | 0% | 18,152 | 0% | 2,824 | 0% | 6,220 | 0% | 5,950 | 0% | 3,614 | 0% |
| 350 - South Oklahoma Folded Belt | 0 | 0% | 4,580 | 0% | 17,422 | 0% | 47,665 | 0% | 38,627 | 0% | 25,359 | 0% |
| 355 - Chautauqua Platform | 39,207 | 1% | 23,253 | 0% | 13,910 | 0% | 9,559 | 0% | 5,357 | 0% | 2,692 | 0% |
| 360 - Anadarko Basin | 1,951,932 | 26% | 1,079,360 | 10% | 79,744 | 1% | 194,986 | 2% | 199,248 | 2% | 8,674 | 0% |
| 375 - Sedgwick Basin | 0 | 0% | 661,828 | 6% | 0 | 0% | 234 | 0% | 3,033 | 0% | 0 | 0% |
| 385 - Central Kansas Uplift | 71,586 | 1% | 90,656 | 1% | 101,570 | 1% | 93,974 | 1% | 28,525 | 0% | 19,500 | 0% |
| 395 - Williston Basin | 3,316,405 | 45% | 5,746,941 | 55% | 7,863,150 | 67% | 9,691,472 | 76% | 8,528,583 | 68% | 5,420,456 | 66% |
| 415 - Strawn Basin | 0 | 0% | 0 | 0% | 0 | 0% | 6,291 | 0% | 0 | 0% | 0 | 0% |
| 420 - Fort Worth Syncline | 39,882 | 1% | 50,428 | 0% | 2,186 | 0% | 4,907 | 0% | 28 | 0% | 25 | 0% |
| 430 - Permian Basin | 677,415 | 9% | 779,460 | 8% | 1,229,008 | 11% | 1,051,295 | 8% | 2,448,137 | 20% | 1,967,988 | 24% |
| 435 - Palo Duro Basin | 19,829 | 0% | 19,510 | 0% | 3 | 0% | 62 | 0% | 1,866 | 0% | 0 | 0% |
| 515 - Powder River Basin | 39,890 | 1% | 77,435 | 1% | 197,564 | 2% | 106,907 | 1% | 69,643 | 1% | 41,490 | 1% |
| 520 - Big Horn Basin | 0 | 0% | 0 | 0% | 0 | 0% | 1,088 | 0% | 944 | 0% | 0 | 0% |
| 535 - Green River Basin | 294 | 0% | 3,626 | 0% | 8,404 | 0% | 3,191 | 0% | 2 | 0% | 0 | 0% |
| 540 - Denver Basin | 267,533 | 4% | 313,901 | 3% | 383,261 | 3% | 228,937 | 2% | 82,878 | 1% | 24,899 | 0% |
| 545 - North Park Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 26,989 | 0% | 40,151 | 0% |
| 575 - Uinta Basin | 22,251 | 0% | 31,682 | 0% | 115,014 | 1% | 48,026 | 0% | 34,872 | 0% | 28,416 | 0% |
| 580 - San Juan Basin | 9,910 | 0% | 10,470 | 0% | 22,593 | 0% | 8,536 | 0% | 13,959 | 0% | 13,795 | 0% |
| 595 - Piceance Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 124 | 0% | 451 | 0% |
| 745 - San Joaquin Basin | 10,487 | 0% | 3,248 | 0% | 9,836 | 0% | 2,557 | 0% | 34,723 | 0% | 7,499 | 0% |
| 820 - AK Cook Inlet Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 83 | 0% | 1 | 0% |
| **TOTAL** | **7,408,353** | **100%** | **10,384,996** | **100%** | **11,699,948** | **100%** | **12,709,097** | **100%** | **12,465,041** | **100%** | **8,202,349** | **100%** |

# Appendix C – GHGRP Subpart W Miscellaneous Production Flaring Emissions, by basin, for RY2011-2016

| Basin | 2011 | | 2012 | | 2013 | | 2014 | | 2015 | | 2016 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total |
| 140 - Florida Platform | 0 | 0% | 31 | 0% | 0 | 0% | 316 | 0% | 95 | 0% | 2,905 | 0% |
| 160 - Appalachian Basin | 0 | 0% | 9,474 | 0% | 156,596 | 3% | 1,508 | 0% | 439 | 0% | 3,091 | 0% |
| 160A - Appalachian Basin (Eastern Overthrust Area) | 10,059 | 0% | 21,295 | 1% | 68,263 | 1% | 44,956 | 1% | 51,167 | 1% | 66,029 | 2% |
| 200 - Black Warrior Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 210 - Mid-Gulf Coast Basin | 58,779 | 2% | 70,807 | 2% | 129,025 | 2% | 150,254 | 3% | 142,160 | 3% | 107,848 | 4% |
| 220 - Gulf Coast Basin (LA TX) | 347,141 | 14% | 625,252 | 16% | 1,313,767 | 25% | 1,311,265 | 25% | 1,301,568 | 30% | 658,331 | 23% |
| 230 - Arkla Basin | 2,447 | 0% | 1,204 | 0% | 79,635 | 2% | 19,459 | 0% | 24,286 | 1% | 2,035 | 0% |
| 260 - East Texas Basin | 43,960 | 2% | 25,802 | 1% | 26,203 | 1% | 15,192 | 0% | 17,847 | 0% | 12,968 | 0% |
| 305 - Michigan Basin | 4,949 | 0% | 14,923 | 0% | 4,402 | 0% | 3,210 | 0% | 3,230 | 0% | 5,215 | 0% |
| 345 - Arkoma Basin | 13 | 0% | 12 | 0% | 12 | 0% | 0 | 0% | 24 | 0% | 9 | 0% |
| 350 - South Oklahoma Folded Belt | 1,075 | 0% | 1,552 | 0% | 1,324 | 0% | 2,418 | 0% | 5,856 | 0% | 7,982 | 0% |
| 355 - Chautauqua Platform | 424 | 0% | 30,371 | 1% | 15,108 | 0% | 29,880 | 1% | 3,408 | 0% | 584 | 0% |
| 360 - Anadarko Basin | 142,911 | 6% | 70,685 | 2% | 145,823 | 3% | 85,971 | 2% | 232,793 | 5% | 143,872 | 5% |
| 375 - Sedgwick Basin | 51 | 0% | 0 | 0% | 0 | 0% | 1,394 | 0% | 0 | 0% | 254 | 0% |
| 385 - Central Kansas Uplift | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 395 - Williston Basin | 913,695 | 38% | 488,554 | 12% | 708,243 | 14% | 1,473,619 | 28% | 910,642 | 21% | 293,829 | 10% |
| 400 - Ouachita Folded Belt | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 415 - Strawn Basin | 5,967 | 0% | 5,587 | 0% | 2,269 | 0% | 7,491 | 0% | 2,365 | 0% | 0 | 0% |
| 420 - Fort Worth Syncline | 6,326 | 0% | 8,690 | 0% | 23,043 | 0% | 35,343 | 1% | 38,969 | 1% | 568 | 0% |
| 425 - Bend Arch | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 430 - Permian Basin | 374,182 | 16% | 2,108,306 | 54% | 1,962,876 | 38% | 1,508,848 | 29% | 1,213,197 | 28% | 1,100,472 | 38% |
| 435 - Palo Duro Basin | 0 | 0% | 0 | 0% | 0 | 0% | 354 | 0% | 390 | 0% | 71 | 0% |
| 450 - Las Animas Arch | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 455 - Las Vegas-Raton Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 507 - Central Western Overthrust | 625 | 0% | 925 | 0% | 701 | 0% | 111 | 0% | 112 | 0% | 120 | 0% |
| 515 - Powder River Basin | 28,534 | 1% | 52,245 | 1% | 105,528 | 2% | 125,437 | 2% | 102,594 | 2% | 34,839 | 1% |
| 520 - Big Horn Basin | 4,122 | 0% | 2,494 | 0% | 177 | 0% | 1,954 | 0% | 1,165 | 0% | 0 | 0% |
| 530 - Wind River Basin | 0 | 0% | 373 | 0% | 528 | 0% | 621 | 0% | 129 | 0% | 28 | 0% |
| 535 - Green River Basin | 84,576 | 4% | 158,743 | 4% | 255,830 | 5% | 59,517 | 1% | 55,234 | 1% | 54,918 | 2% |
| 540 - Denver Basin | 61,760 | 3% | 13,454 | 0% | 10,950 | 0% | 89,192 | 2% | 118,692 | 3% | 153,414 | 5% |
| 545 - North Park Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| 575 - Uinta Basin | 4,588 | 0% | 16,025 | 0% | 2,702 | 0% | 12,325 | 0% | 8,066 | 0% | 14,383 | 1% |
| 580 - San Juan Basin | 394 | 0% | 71 | 0% | 39,238 | 1% | 70,284 | 1% | 28,342 | 1% | 187 | 0% |
| 585 - Paradox Basin | 236,981 | 10% | 146,578 | 4% | 113,924 | 2% | 161,528 | 3% | 61,032 | 1% | 55,460 | 2% |
| 595 - Piceance Basin | 14,247 | 1% | 5,043 | 0% | 5,828 | 0% | 4,507 | 0% | 3,257 | 0% | 4,828 | 0% |
| 730 - Sacramento Basin | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |

| Basin | 2011 | | 2012 | | 2013 | | 2014 | | 2015 | | 2016 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total | Total CO2 + CH4 Emissions (mt CO2e) | % of Total |
| 740 - Coastal Basins | 0 | 0% | 0 | 0% | 0 | 0% | 136 | 0% | 136 | 0% | 0 | 0% |
| 745 - San Joaquin Basin | 16,360 | 1% | 13,884 | 0% | 15,494 | 0% | 8,547 | 0% | 16,082 | 0% | 26,941 | 1% |
| 750 - Santa Maria Basin | 0 | 0% | 0 | 0% | 2,204 | 0% | 864 | 0% | 232 | 0% | 277 | 0% |
| 760 - Los Angeles Basin | 933 | 0% | 2,486 | 0% | 2,191 | 0% | 1,591 | 0% | 1,548 | 0% | 0 | 0% |
| 820 - AK Cook Inlet Basin | 1,716 | 0% | 2,118 | 0% | 3,263 | 0% | 2,151 | 0% | 514 | 0% | 490 | 0% |
| 890 - Arctic Coastal Plains Province | 35,172 | 1% | 25,434 | 1% | 26,837 | 1% | 11,040 | 0% | 11,188 | 0% | 119,898 | 4% |
| **TOTAL** | **2,401,985** | **100%** | **3,922,418** | **100%** | **5,221,983** | **100%** | **5,241,284** | **100%** | **4,356,758** | **100%** | **2,871,844** | **100%** |

# Exhibit 5

# Camera, Thermal Imaging, 14.5 Degrees (38mm) Fixed Lens

**Description:** Camera,Thermal Imaging, 14.5 Degrees (38mm) Fixed Lens, FLIR GF320 Part No. 44401-0101, Plus Freight

## Item Details

**Price: $86,950.00**
**UOM:** EACH
**Contractor:** Flir Commercial Systems
**Contract Number:** 655-A1 (/contracts/view/1897)
**Contract Type:** Term
**Commodity Code:** 65535420012
**Min. Order Quantity:** 1
**Delivery Days:** 90
**NIGP Code:** 65535
**Item Availability Start Date:** 2/22/2017
**Item Availability End Date:** 10/31/2020
**Supplier Part Number:** 65535420012
**Manufacturer Part #:** GF320 44401-0101
**Manufacturer:** FLIR

Add to wish list (/product/6250620?itemdetail)


FLIR GF300
FLIR SYSTEMS

# Exhibit 6

Regional Air Quality Council
1445 Market Street, Suite 260
Denver, Colorado 80200

# PERSONAL PROPERTY LOAN AGREEMENT

1. Loan Number: SAMPLE

2. Loan Date: From: __________ To: ___________

3. Recipient:

Address:

Point of Contact:

Phone/Fax/Email:

4. Purpose of Loan:
Recipient employees have been trained and certified in use of the FLIR Camera. They will use this tool to identify and repair leaks from oil and gas faciliities that result in methan, VOC, and HAP emissions as noted in the Terms and Conditions.

5. The property described below is offered by the Regional Air Quality Council for use without charge to the recipient named above for a period not to exceed ___________.

| Item Number | Description | Serial Number | Acquisition Cost |
|---|---|---|---|
| 1 | FLIR GF320 24°,<br>as described in the attached T.D. sheet | #### | $$ |



6. This agreement is entered into with the understanding that the property identified shall remain that of the Regional Air Quality Council and that this agreement may be terminated by submission of a ______ day prior written notice to the recipient by the Regional Air Quality Council (see full terms and condition on reverse.)

## Regional Air Quality Council

______________________________ ______________
Signature of RAQC Authorized Official — Date
Misty Howell, Office Manager

## Recipient

______________________________ ______________________________
Printed Name — Signature

______________________________ ______________
Title — Date

# Terms and Conditions of Loan

1. The Recipient shall:

   A. provide to the RAQC identification and location of leaks by county, including description of kind of equipment (valves, tanks, pumps, pipes, heater/treaters etc.) involved, location of leak on equipment, repair action taken, repair date, and an estimate of the size of the leaks and, where possible, the emissions reduced by the repair;

   B. return the loaned property in like condition as when received from the Regional Air Quality Council, normal wear and tear excepted, and free of contamination, on or before the expiration date (as set forth in Section 2 of the first page of this Loan Agreement), unless the loan period is formally extended or terminated before the expiration date;

   C. in case of loss, theft or damage of the loaned property, reimburse the Regional Air Quality Council at the current price of the replacement or repair;

   D. assume all costs invloved in preparing, handling, loading, disconnecting, and transporting the loaned property from and to the RAQC;

   E. indemnify and hold harmless the Regional Air Quality Council against any and all liability loss, damanges, claims, and costs incidental thereto as a result of Recipient's use or possession on the loaned property; and

   F. use the loaned property only for the purpose specified in the loan agreement.

2. The loaned property shall not be modified, loaned, or transferred to a third party without the prior written permission of the Regional Air Quality Council.

3. The Recipient shall account for, or permit physical inpsection of the loaned property by the Regional Air Quality Council after notification from the Regional Air Quality Council.

4. Title to the loaned property is vested in and will remain with the Regional Air Quality Council and the loaned property shall be used only for offical purposes as described in Section 4 of the first page of this Loan Agreement.

I have read and understand the terms and conditions of this loan agreement.



Signature Date

Print Name and Title

# Regional Air Quality Council (RAQC)

## Recipient Employee Agreement for Handling and Security of RAQC FLIR Infrared Camera

I, ___________________________________, agree to the following handling and security procedures at all times when in possession of the RAQC FLIR Infrared Camera (IR Camera):

1) Prior to each time a recipient employee checks out the IR Camera from the RAQC, this form shall be read, signed and dated by the employee, and the employee's supervisor. The employee shall indicate the dates that the camera will be in the employee's possession, as noted on the form below.

2) When the IR Camera is in the recipient employee's possession, it shall be handled handled with reasonable care and diligence to the greatest extent possible.

3) When the IR Camera is in the recipient employee's possession, including overnight, it shall be stored in a lockable and secure area, which may include a responsible employees's office or locking storage cabinet or a locking storage area.

4) The IR Camera shall not be taken home by the responsible recipient employee.

5) The IR Camera shall not be left unattended in a vehicle even when the vehicle is locked. Exceptions when traveling with the camera may include when the responsible recipient employee strops to refill the vehicle for gasoline, so long as the vehicle remains within sight or view of the employee to the greatest extent possible during this time period.

The RAQC IR Camera is being checked out by the noted recipient employee below from the following date:___________________ to the following date: _________________________.

_________________________________________
Company Name



_________________________________________ ____________
Employee Date

_________________________________________ ____________
Supervisor Date

REGIONAL AIR QUALITY COUNCIL

FLIR GF320 24◦ Optical Imaging Camera
List of Transport Case Materials and Equipment

Equipment

- Hard transport case (P/N 44401189)
- Infrared camera with lens (SN: 44401189)
- Battery, 2 ea. (P/N1196209-20) SRL-No. 004345 & 004292
- Shoulder strap
- Lens cap (2 ea.)
- Lens cap (mounted on lens)
- Mirco SD Memory card (2GB)
- 2 Memory card adapters (MicroSD to Mini SD; MicroSD to SD)
- WiFi USB mirco adapter & strap (EDIMAX 9577110814)
- Verbatim MiniSD/SD Pocket card reader (model 47128)
- Battery charger (NS 008625; P/N 1196210)
- Power supply, incl. multi-plugs (P/N 10231014)
- HDMI-DVI cable (P/N T910816)
- HDMI-HDMI cable (P/N T910815)
- USB cable (P/N T910423)
- Vista Voyages Lite Tripod with carrying case

Materials

- Printed Getting Started Guide
- Printed Important Information Guide
- Service & training brochure
- Downloads brochure
- User documentation CD-ROM (P/N T197554-11)
- FLIR QuickReport™ PC software CD-ROM (P/N T197965-05)
- FLIR VideoReport™ PC software CD-ROM (P/N T197556-08)