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Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production

Report for Oil and Natural Gas Sector
Oil Well Completions and Associated Gas during Ongoing Production
Review Panel

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Prepared by

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PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:
www.epa.gov/airquality/oilandgas/whitepapers.html

1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater air emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing) which allows for drilling in formerly inaccessible formations.

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on air emissions and available mitigation options. This paper presents the Agency's understanding of air emissions and available control technologies from a potentially significant source of emissions in the oil and natural gas sector.

Oil and gas production from unconventional formations such as shale deposits or plays has grown rapidly over the last decade. Oil and natural gas production is projected to steadily increase over the next two decades. Specifically, natural gas development is expected to increase by 44% from 2011 through 2040 (U.S. EIA, 2013b) and crude oil and natural gas liquids (NGL) are projected to increase by approximately 25% through 2019 (U.S. EIA, 2013b). The projected growth of natural gas production is primarily led by the increased development of shale gas, tight gas, and coalbed methane resources utilizing new production technology and techniques such as horizontal drilling and hydraulic fracturing. According to the U.S. Energy Information Administration (EIA), over half of new oil wells drilled co-produce natural gas (U.S. EIA, 2013a). Based on this increased oil and gas development, and the fact that half of new oil wells co-produce natural gas, the potential exists for increased air emissions from these operations.

One of the activities identified as a potential source of emissions to the atmosphere during oil development is hydraulically fractured oil well completions. Completion operations are conducted to either bring a new oil well into the production phase, or to maintain or increase the well's production capability. Although the term "recompletion" is sometimes used to refer to completions associated with refracturing of existing wells, this paper will use the term "completion" for both newly fractured wells and refractured wells. In addition, hydraulically fractured coproducing oil wells can generate emissions of associated gas during the production phase. These processes and emissions are described in detail in Section 2.

The purpose of this paper is to summarize the EPA's understanding of VOC and methane emissions from hydraulically fractured oil well completions and associated gas during ongoing production. It also presents the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry.

2.0 DEFINITION OF THE SOURCE

2.1 Oil Well Completions

For the purposes of this paper, a well completion is defined to mean:

> The process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Completion operations with hydraulic fracturing are conducted to either bring a new oil well into the production phase or to maintain or increase the well's production capability (sometimes referred to as a recompletion). Well completions with hydraulic fracturing include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and are installed as necessary for production to begin.

For the purposes of this paper, hydraulic fracturing is defined to mean:

> The process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic fracturing is one technique for improving oil and gas production where the reservoir rock is fractured with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that “props open” the fractures after fluid pressure is reduced.

Oil well completions with hydraulic fracturing can result in VOC and methane emissions, which occur when gas is vented to the atmosphere during flowback. The emissions are a result of the backflow[1] of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This comingled fluid stream (containing produced oil, natural gas and water) flows from each drilled well to a respective vertical separator and heater/treater processing unit. Fluid may be heated to aid in separation of the oil and natural gas and produced water. Phase separation is the process of removing impurities from the hydrocarbon liquids and gas to meet sales delivery specifications for the oil and natural gas. Oil may go directly to a pipeline or be stored onsite for future transfer to a refinery. If infrastructure is present, produced gas can be metered to a sales pipeline. If infrastructure is not available, the produced gas is frequently sent to combustion devices for destruction (e.g., flares) or is vented to the atmosphere.

Recompletions are conducted to minimize the decline in production, to maintain production, or in some cases to increase production. When oil well recompletions using hydraulic fracturing are performed, the practice and sources of emissions are essentially the same as for new well completions involving hydraulic fracturing, except that surface gas collection

[1] Backflow is the phenomena created by pressure differences between zones in the borehole. If the wellbore pressure rises above the average pressure in any zone, backflow will occur (i.e., fluids will move back towards the borehole). In contrast, “flowback” is the term used in the industry to refer to the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.(http://www.glossary.oilfield.slb.com/)

equipment may already be present at the wellhead after the initial fracture. However, the backflow velocity during refracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

2.2 Associated Gas

Associated gas is the term typically used for natural gas produced as a by-product of the production of crude oil. Industry publications typically refer to associated gas as gas that is co-produced with crude oil while the well is in the production phase and is vented directly to the atmosphere or is flared. One published definition for associated gas is "gaseous hydrocarbons occurring as a free-gas phase under original oil-reservoir conditions of temperature and pressure (also known as gas-cap gas)."[2] Therefore, associated gas can include gas that is produced during flowback associated with completion activities and gas that is emitted from equipment as part of normal operations, such as natural gas driven pneumatic controllers and storage vessels. However, in this paper, the term "associated gas emissions" refers to:

> Associated gas emissions from the production phase (i.e., excluding completion events and emissions from normal equipment operations) that could be captured and sold rather than being flared or vented to the atmosphere if the necessary pipeline and other infrastructure were available to take the gas to market.

3.0 EMISSIONS DATA AND EMISSIONS ESTIMATES – HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS

For consistency in the review of the various data sources and studies and to better understand the data discussions presented below, this section presents an overview of the types of the emissions estimation processes and the data that have been used in a number of studies to estimate VOC and methane emissions from hydraulically fractured oil well completions and recompletions.

[2] McGraw-Hill Dictionary of Scientific & Technical Terms, 6E, Copyright © 2003 by the McGraw-Hill Companies, Inc.

1) For estimating source emissions:
   - Gas produced during completions of oil wells. Estimated. This type of data would provide natural gas or methane production volumes for a completion. The data may be estimated using well characteristics (e.g., flow rate, casing diameter, and casing pressure) and established emission factors.
   - Gas produced by the oil well annually/daily/monthly. Direct measure or estimated. This type of data would be similar to the gas produced during completions but would be related to ongoing production of associated gas from the well.
   - Gas composition. This data is typically composition results from laboratory analysis of the raw gas stream to determine methane and other hydrocarbon volume or weight percent for use in converting natural gas or methane emissions estimates to VOC.
   - Duration of completion cycle. Length of the completion process in days.
   - Use of control technology. Flares, reduced emissions completions (RECs), other control technology or none. This information indicates whether a control device or practice is used and, if possible, the amount of produced gas captured and controlled.
2) For estimating nationwide emissions:
   - Number of oil well completions conducted annually. This information requires identification of the number of oil wells conducting completions/recompletions annually.
   - Number of oil wells co-producing natural gas. This involves identifying the population of oil wells using a definition of oil well based on some production criteria.
   - Number of oil wells completions with emissions controls such as RECs or flaring.

There are several available data sources for the data elements described above. Because most of the available data were not collected specifically for the purpose of estimating emissions, each source has to be qualified to ensure that the data are being used appropriately. In characterizing the nationwide emissions, we analyzed several sources of data and qualify each source with respect to the different aspects of the emission estimation process. Therefore, in addition to describing the data source and any relevant results of analysis, this paper discusses the implications of the data and/or results of analysis of the data with respect to the quantity of data, quantity of emissions, scope of emissions estimates, geographic dispersion, and variability in data.

Lastly, methodologies used in the emission estimation process are described, such as a discussion of the methodology for deriving emission factors or for identifying national populations.

There is variation in the industry as to how oil wells and gas wells are defined. Some publications do not differentiate at all between them, while others use the amount of oil produced or a gas-to-oil ratio (GOR) threshold as a dividing line between a gas well and an oil well. This paper does not attempt to choose a specific definition of "oil well," but instead describes the definitions used in each study or data source. The intent of this section of the paper is to present the EPA's understanding of the available data and its usefulness in estimating VOC and methane emissions from this source.

3.1 Summary of Major Studies and Sources of Emissions Data

Given the potential for emissions from hydraulically fractured oil well completions, there have been several information collection efforts and studies conducted to estimate emissions and available emission control options. Studies have focused on completion emission estimates. Some of these studies are listed in Table 3-1, along with an indication of the type of information contained in the study (i.e., activity level, emissions data, and control options).

Table 3-1. Summary of Major Sources of Information and Data on Oil Well Completions

Name	Affiliation	Year of Report	Activity Factor	Uncontrolled/Controlled Emissions Data	Control Options Identified
Fort Berthold Federal Implementation Plan (U.S. EPA, 2012a)	U.S. Environmental Protection Agency	2012	Regional	Uncontrolled	X
ERG/ECR Contractor Analysis of HPDI® Data	U.S. Environmental Protection Agency	2013	Nationwide	Uncontrolled	X
Environmental Defense Fund Analysis of HPDI® Data (EDF, 2014)	Environmental Defense Fund	2014	Nationwide	Uncontrolled	-

Name	Affiliation	Year of Report	Activity Factor	Uncontrolled/Controlled Emissions Data	Control Options Identified
Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	26 Completion Events	Both	-
Methane Leaks from North American Natural Gas Systems (Brandt et. al, 2014a and 2014b)	Multiple Affiliations	2013	Regional	Uncontrolled	-

Data for Petroleum and Natural Gas Systems collected under the EPA's Greenhouse Gas Reporting Program (GHGRP) or the EPA's Inventory of U.S. Greenhouse Emissions and Sinks (GHG Inventory), are not discussed in detail in this section. The GHGRP does not require reporting of vented emissions from hydraulically fractured oil well completions. The GHG Inventory estimates emissions from oil well completions, but does not distinguish between completions/recompletions of conventional wells and completions/recompletions of hydraulically fractured wells.

A more-detailed description of the data sources listed in Table 3-1 is presented in the following sections, including how the data may be used to estimate national VOC and methane emissions from oil well completion events.

3.2 Fort Berthold Federal Implementation Plan (FIP) – Analysis by EC/R (U.S. EPA) 2012a)

On March 22, 2013, the EPA published (78 FR 17836) the FIP for existing, new and modified oil and natural gas production facilities on the Fort Berthold Indian Reservation (FBIR). In support of that effort, the EPA conducted an analysis of 154 applications for synthetic minor New Source Review (NSR) permits that indicated VOC emissions were the most prevalent of the pollutants emitted from the oil and natural gas production sources operating on the FBIR, which contain equipment that handles natural gas produced during well completions, phase separation during production, and temporary storage of crude oil (U.S. EPA, 2012).

The EPA FIP established federally enforceable requirements to control VOC emissions from oil and natural gas production activities that were previously unregulated or regulated less strictly. The FIP requires a 90%-98% reduction of VOC emissions from gas not sent to a sales line using pit flares, utility flares and enclosed combustors, all technologies which were found to be standard industry practice on the FBIR. The analysis included a large dataset of combustion control equipment cost information based on three well/control configuration scenarios.

The FBIR dataset includes:

- 533 production wells from five major operators
- Average controlled and uncontrolled VOC emissions from oil wells for wellhead gas, heater/treaters, and storage tanks
- Oil production data
- Number of sources; storage tanks, combustors, flares, and if a pipeline is present
- Current capital and annualized cost estimates for combustion and REC control options
- Gas composition data (for each permit application)
- Projected 2,000 new wells or 1,000 well pads per year between 2010 and 2029.

The data provided for the FBIR, although useful, has certain qualifying limitations. For instance, the FBIR data is primarily for wells producing from the Bakken and Three Forks formations, which limits it to a regional dataset. Also, the FBIR data showed high variability in oil well production rates and in product composition. This variability may not be representative of other formations. Also, according to the North Dakota Department of Health, the Bakken formation typically contains a high amount of lighter end VOC components which have the potential to produce increased volumes of flash emissions compared to typical oil production wells (U.S. EPA, 2012a). This may be somewhat unique to the Bakken formation and not be representative nationally.

Table 3-2 summarizes an analysis performed by EC/R of the FBIR data with respect to oil well completion emissions. The analysis estimated completion emissions by multiplying the average gas volume per day for each well by a 7 day flowback period. The analysis indicated that the average uncontrolled emissions from a well completion event are 37 tons of VOC per completion event.

Table 3-2. Summary of FBIR FIP Oil Well Completion Uncontrolled[3] Casing Gas and VOC Emissions

	Data from FBIR FIP											
Data Element	**Enerplus**	**EOG**	**QEP[c]**	**WPX[b]**	**WPX-2[b]**	**WPX-3[b]**	**XTO[d]**	**Marathon**	**PetroHunt**	**Average**	**Min**	**Max**
VOC Molecular weight	27.0	27.7	NA	28.1	29.6	31.7	24.5	28.5	25.8	27.8	24.5	31.7
Natural Gas Molecular weight	37.8	40.5	NA	43.7	45.9	51.0	32.9	41.4	34.3	41.0	32.9	51.0
Gas Constant (ft^3/lbmol)[a]	379	379	NA	379	379	379	379	379	379	379	379.0	379
Average Oil Production (bpd) - per well	1,181	255	NA	347	420	303	305	2,094	214	639.7	214	2,094
Average Gas Volume (Mcf/day) - per well	885	182	NA	250	292	210	305	491	197	351.5	182	885
Average Gas Volume (Mcf/completion)	6,197	1,272	NA	1,748	2,042	1,473	2,133	3,439	1,378	2,460	1,272	6,197
Average Uncontrolled VOC Emissions (ton/completion)	83	19	NA	28	37	31	23	53	16	37	16	83

NA = Not Reported, FBIR FIP = Fort Berthold Indian Reservation Federal Implementation Plan, EOG = EOG Resources, QEP = QEP Energy Co., WPX = WPX Energy, XTO = XTO Energy Inc.
a-Value used by North Dakota facilities represents 60°F and 1 atm. For subpart OOOO, this value is based on 68°F and 1 atm.
b-NOTE for WPX:
i. They used three different molecular weights and percent. Therefore, each of these are represented in this table.
ii. They only reported 10% of the VOC emissions because they flare 90% of their casinghead gas emissions. This table represents 100%.
c-The QEP molecular weight and VOC content data for casinghead gas were claimed as copyrighted and were not in the online docket.
d-XTO reported oil production and associated gas production as the same value. Therefore, did not include this gas to oil production ratio in the average.

[3] Uncontrolled emissions are the emissions that would occur if no emissions mitigation practices or technologies were used (*e.g.*, completion combustion devices or RECs).

3.3 ERG Inc. and EC/R Analyses of HPDI Data

ERG Inc. and EC/R (ERG/ECR) conducted an analysis of Calendar Year (CY) 2011 HPDI[4] data to estimate uncontrolled emissions from hydraulically fractured oil well completions for the EPA. For this analysis the following methodology was used:

ERG extracted HDPI oil well data for hydraulically fractured, unconventional oil wells completed in CY 2011. Because the HPDI database does not differentiate between gas and oil wells, the following criteria were used to identify the population of hydraulically fractured oil well completions:

- Identified wells completed in 2011 using HPDI data covering U.S. oil and natural gas wells. Summary of the data and the logic for dates used is included in the memo "Hydraulically Fractured Oil Well Completions" (ERG, 2013)
- Identified wells completed in 2011 that were hydraulically fractured using the Department of Energy EIA formation type crosswalk supplemented with state data for horizontal wells (ERG, 2013)
- Determined which wells were oil wells based on their average gas-to-liquids ratio (less than 12,500 scf/barrel were considered to be oil wells)
- Estimated the average daily gas flow from the cumulative natural gas production for each well during its first 12 months of production
- The resulting dataset provided 192 data points representing county level average daily natural gas production at a total of 5,754 oil well completions for CY 2011.

Emissions in the ERG/ECR analysis were calculated using both a 3-day and a 7-day flowback period. The volume of natural gas emissions (in Mcf) per completion event was calculated using the average daily flow multiplied by both a 7-day flowback period and a 3-day flowback period. The gas volume was converted to mass of VOC using the same VOC

[4] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data. For certain states and regions, this data was supplemented by state drilling information. The 2011 data was the most current data available when the analysis was performed.

composition and conversion methodology used for gas wells in the subpart OOOO well completion evaluation. The composition values used were 46.732% by volume of methane in natural gas and 0.8374 pound VOC per pound of methane for oil wells (EC/R, 2011a).

The analysis of the 2011 HPDI data for oil well completions provided an average gas production of 262 Mcf per well per day. Based on this gas production, the average uncontrolled VOC emissions were 20 tons per completion event based on a 7-day flowback period and 6.4 tons of VOC per completion event based on a 3-day flowback period. The average uncontrolled methane emissions were 24 tons per completion event based on a 7-day flowback period and 7.7 tons of methane per completion event based on a 3-day flowback period. It was assumed that the emissions for an oil well recompletion event are the same as an oil well completion event.

To estimate nationwide uncontrolled emissions for hydraulically fractured oil well completions, the average methane and VOC emissions per event were multiplied by the total number of estimated oil well completions. For 2011, which was the most recent data available in HPDI, the estimated nationwide uncontrolled hydraulically fractured oil well completion VOC emissions are 116,230 tons per year (i.e., VOC emissions/completion of 20.2 tons/event times the total oil well completion events per year of 5,274) based on a 7-day flowback period and 36,825 tons per year (i.e., VOC emissions/completion of 6.4 tons/event times the total oil well completion events per year of 5,274) based on a 3-day flowback period. The estimated nationwide uncontrolled hydraulically fractured oil well completion methane emissions are 138,096 tons per year (i.e., methane emissions/completion of 24 tons/event times the total oil well completion events per year of 5,274) based on a 7-day flowback period and 44,306 tons per year (i.e., VOC emissions/completion of 7.7 tons/event times the total oil well completion events per year of 5,274) based on a 3-day flowback period. Table 3-3 presents the results of the emission estimate analysis for both the 7-day and 3-day completion duration periods.

Table 3-3. Summary of Oil Well Completion Uncontrolled Emissions from 2011 HPDI Data

	7-day event	3-day event
Total number of hydraulically fractured oil well completions in 2011	5,754	5,754
Number of county well production averages (data points)	195	195
Natural Gas production per well, per day, weighted average (Mcf)	262	262
Methane emissions per completion/recompletion event, weighted average (tons)	24	7.7
VOC emissions per completion/recompletion event, weighted average (tons)	20.2	6.4
Uncontrolled Nationwide methane emissions, oil well completions (tpy)	138,096	44,306
Uncontrolled Nationwide VOC emissions, oil well completions (tpy)	116,230	36,825

Note: This estimate does not include recompletion emissions.

As stated earlier, these estimates are for uncontrolled emissions, thus estimates assume no control technology applied. National-level data on the prevalence of the use of RECs or combustors for reduction of emissions from oil well completion or recompletion operations were unavailable for this analysis.

State level information for Colorado, Texas and Wyoming on oil well recompletion counts was used to determine a percentage of producing wells for which recompletions were reported. The state level data were obtained for Colorado, Texas and Wyoming for recent years (COGCC, 2012, Booz, 2008 and RRCTX, 2013). Based on the state level data, it was determined that the average percentage of producing well undergoing recompletion was 0.5%. This includes both conventional and hydraulically fractured oil wells (the data did not allow the different types of wells to be distinguished from each other). Table 3.4 presents a summary of this analysis.

Table 3-4. Analysis of Texas, Wyoming and Colorado Recompletions Counts

State Data Source	Year	Total Number of Producing Wells	Total Number of Recompletions	Percent Recompletions to Total Producing Wells
Railroad Commission of Texas	2012	168,864	685	0.4
Wyoming Heritage Foundation	2007	37,350	304	0.8
State of Colorado Oil & Gas Conservation Commission	2012	50,500	152	0.3
Average Percent				**0.5**

While the state level recompletion data are recent, the percentage of producing oil wells that undergo recompletion in future years may increase due to more prevalent use of hydraulic fracturing on oil wells. However, no data have been obtained to quantify any potential increase in the oil well recompletion rate. This percentage was not used to estimate the number of recompletions of hydraulically fractured oil wells, because the data did not distinguish between conventional wells and hydraulically fractured wells.

3.4 Environmental Defense Fund and Stratus Consulting Analysis of Oil Well Completions[5] (EDF, 2014)

The Environmental Defense Fund (EDF) and Stratus Consulting (EDF/Stratus) conducted an analysis of HPDI data for oil wells to determine the cost effectiveness of the use of RECs and flares for control of oil well completion emissions within three major unconventional oil play formations, Bakken, Eagle Ford and Wattenberg. The oil well completion population was extracted using the DI Desktop for all oil wells with initial production in 2011 and 2012. Different filters were applied in each formation in order to identify the hydraulically fractured oil wells:

[5] This analysis is described in the EDF white paper "Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses" (http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf). It is referred to in that paper as the "EDF/Stratus Analysis." The supplemental materials, including the data that was used in the analysis are available at https://www.dropbox.com/s/osrom4w6ewow4ua/EDF-Initial-Production-Cost-Effectiveness-Analysis.xlsx.

- Eagle Ford
    - Well Production Type: Oil
- Bakken
    - Well Production Type: Oil and Oil & Gas
- Wattenberg
    - Well Production Type: Oil

The resulting dataset included 3,694 oil wells for the Bakken formation, 1,797 oil wells for the Eagle Ford formation, and 3,967 oil wells for the Wattenberg formation. The assumptions EDF/Stratus made while conducting this analysis were:

- Well completions lasted an average of 7 to 10 days and the total gas production over that period was equal to 3 days of "Initial Gas Production" as reported in DI Desktop (i.e., 3 days of "Initial Gas Production" was equal to the uncontrolled natural gas emissions from the oil well completion).
- The natural gas content was 78.8% methane.

Table 3-5 summarizes the results of this analysis.

Table 3-5. EDF Estimated Uncontrolled Methane Emissions from Oil Well Completions Based on Analysis of HPDI® Oil Well Production Data

Formation	Wells (#)	Uncontrolled Completion Emissions (gas Mcf/event)	Uncontrolled Completion Emissions (MT CH_4/event)	Uncontrolled Completion Emissions (tons CH_4/event)
Wattenberg[a]	3,967	624	9.5	10.5
Bakken[b]	3,694	1,183	18.0	19.8
Eagle Ford[c]	1,797	1,628	24.7	27.2

All results represent mean values.
a - Production data was downloaded for all oil wells in the Colorado Wattenberg formation with a first production date between 1/1/2010 and 3/1/2013.
b - Production data was downloaded for wells in the North Dakota Bakken formation with a completion date from 1/1/2010-12/31/2012. North Dakota does not distinguish between oil and gas wells. All wells with the type O&G were assumed to be oil wells.
c - Production data was downloaded for all oil wells in the Texas Eagle Ford formation with a completion date between 1/1/2010 and 2/23/2013.

The EDF/Stratus Analysis also provided an estimate of uncontrolled methane emissions from oil well completions of 247,000 MT (272,000 tons), however, the materials describing the analysis do not explain how this estimate was calculated.

3.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (UT Study) (Allen et al., 2013)

The UT Study was primarily authored by University of Texas at Austin and was sponsored by the EDF and several companies in the oil and gas production industry. The study was conducted to gather methane emissions data at onshore natural gas well sites in the U.S. and compare the data to the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). The sources and operations that were tested included well completion flowbacks, well liquids unloading, pneumatic pumps and controllers and equipment leaks. The full study analysis included 190 onshore natural gas sites, which included 150 production sites, 26 well completion events, 9 well unloading and 4 well recompletions or workovers.

Six of the completion events in the UT Study were at co-producing wells (at least some oil was produced). The study reported the total oil produced, the total associated gas produced, the potential and actual methane emission, the completion duration, the type of emission control used, and the percent reduction from the control that was observed (Note: for two of the completion events, data was not gathered for the initial flow to the open tank). The data for these wells are summarized in Table 3-6.

Table 3-6. Summary of Completion Emissions from Co-Producing Wells

Site ID	Oil Produced (bbl)	Gas Produced (Mcf)	GOR (scf/bbl)	Potential Methane Emissions[a] (Mcf)	Actual Methane Emissions[b] (Mcf)	% Reductio n	Data Analyzed	Duration (hrs)	REC or Flare
GC-1	1,594	6,449.9	4,046.36	5,005	106	97.9	Yes	75	Flare
GC-2	1,323	5,645	4,266.82	4,205	91	97.8	Yes	76	Flare
GC-3	2,395	26,363	11,007.52	21,500	264	98.8	Yes	28	REC
GC-4	1,682	24,353	14,478.60	13,000	180	98.6	Yes	28	REC
GC-6	448	13,755	30,703.13	12,150	247	98	No[d]	164	Flare
GC-7	1,543	5,413	3,508.10	4,320	90	97.9	No[d]	108	Flare

a – Measured emissions before flare or REC.
b - Measured emissions after flare or REC.
c - Calculated from measured before and after control.
d -Data not used in developing average emissions factor in the UT Study because, in these flowbacks, the study team was unable to collect completion emissions data for the initial flow to the open tank.

Using the threshold of a GOR of 12,500 scf/barrel to distinguish oil wells from gas wells, wells GC-1, GC-2, GC-3, and GC-7 would be considered oil wells. The average uncontrolled methane emissions from those wells were 213 tons (10,237 Mcf) and the average controlled (actual) emissions were 3.2 tons (154 Mcf).[6] The average duration of the completion for these wells was 72 hours (3 days). It is also worth noting that well GC-3 was controlled using a REC and 98.8% of the potential methane emissions were mitigated, demonstrating that RECs can be used effectively to control emissions from hydraulically fractured oil wells.

3.6 Methane Leaks from North American Natural Gas Systems (Brandt et. al, 2014a and 2014b)

Novim, a non-profit group at the University of California, sponsored a meta-analysis of the existing studies on emissions from the production and distribution of natural gas. As part of this analysis, Novim estimated emissions from hydraulically fractured oil well completions based on data from HPDI®. Novim included wells that were drilled in 2010 or 2011 in the Eagle Ford,

[6] These averages do not include well GC-7, because, as noted above, data from this well was not used in the UT Study due to the inability to collect all the emissions data.

Bakken, and Permian formations (Brandt et. al., 2014a). Different filters were applied in each formation in order to identify the hydraulically fractured oil wells:

- Eagle Ford
  - Well Production Type: Oil
  - Drill Type: Horizontal
- Bakken
  - Well Production Type: Oil and Oil & Gas
  - Drill Type: Horizontal
- Permian
  - Well Production Type: Oil
  - Drill Type: All

Using this method of qualifying the well population, Novim concluded 2,969 hydraulically fractured oil wells were completed in 2011 in the three formations (Brandt et. al., 2014a). In order to estimate completion emissions, Novim used the O'Sullivan method[7] in which peak gas production (normally the production during the first month) is converted to a daily rate of production. The O'Sullivan method assumes that during flowback emissions increase linearly over the first nine days until the peak rate is reached. Table 3-7 summarizes the estimated uncontrolled methane emissions per completion calculated by the Novim study.

Table 3-7. Summary of Uncontrolled Completion Emissions from Co-Producing Wells

Formation	Uncontrolled Methane Emissions (tonnes/event)[a]	Uncontrolled Methane Emissions (ton/event)[b]
Eagle Ford	90.9	93
Bakken	31.1	31.9
Permian	31.2	31.9

a – 1 Mg = 1 metric tonne of methane
b – Converted to U.S. short tons. 1 tonne = 1.02311 tons (short/U.S.) of methane

[7] O'Sullivan, Francis and Sergey Paltsev, "Shale gas production: potential versus actual greenhouse gas emissions", Environmental Research Letters, United Kingdom. November 26, 2012.

The Novim Study assumes methane emissions from these formations are representative of total national methane emissions from hydraulically fractured oil well completions and estimates those emissions to be 0.12 Tg (120,000 tonnes or 122,773 tons) per year for 2011.

It should be noted that the methodology in this study, like the ERG/ECR Analysis and the EDF/Stratus Analysis, uses gas production from HPDI® to estimate completion emissions. However, Novim uses the O'Sullivan method in which the emissions increase linearly through the flowback period until a peak is reached, while the ERG/ECR Analysis and the EDF/Stratus Analysis assume emissions are constant through the flowback period.

4.0 EMISSIONS DATA AND EMISSIONS ESTIMATES – ASSOCIATED GAS FROM HYDRAULICALLY FRACTURED OIL WELLS

Given the potential for emissions of associated gas from oil production, available information sources have been reviewed as to their potential use for characterizing the VOC and methane emission from associated gas production at oil well sites. As was stated previously, the term "associated gas emissions" in this paper refers to emissions from gas that is vented during the production phase that could otherwise be captured and sold if the necessary pipeline infrastructure was available to take the gas to market.

One methodology for estimating emissions would be to use the GOR of the well, which is a common piece of well data in the industry. An emission factor based on average GOR could be developed, and then the emission factor could be used to estimate uncontrolled associated gas emissions by applying it to known oil production (assuming all gas produced at an oil well is included in uncontrolled associated gas emissions). However, research indicates that associated gas production from oil wells declines over the life of the well, similar to oil production, but the decline is typically at a different rate than the oil production (EERC, 2013). This phenomenon introduces another variable into the analysis.

A second approach would be to use gas production reported for the well for economic and regulatory reasons. Conceivably, gas production could be used to estimate uncontrolled associated gas emissions. However, the EPA is not aware of a methodology that would allow the Agency to calculate the percentage of produced gas that could be captured if pipeline infrastructure were available. Some gas is emitted from equipment as part of normal operations, such as bleeding from pneumatic controllers. These emissions would not qualify as associated gas emissions as they have been defined in this paper.

The GHGRP does require reporting of "associated gas venting and flaring emissions." Additionally, the Ceres report contains data potentially useful for basic evaluation of VOC and methane associated gas emissions, but does not provide national estimates or per well estimates of emissions (Ceres, 2013). Both these sources are discussed in detail in the sections below.

The GHG Inventory does not include a category that specifically covers all associated gas emissions. Instead, these emissions are estimated in several categories in Petroleum Systems, and in Natural Gas Systems (emissions downstream of the gas-oil separator, and flaring).

4.1 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[8] collected under the GHGRP. The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

When reviewing this data and comparing it to other datasets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems; a facility[9] in the Petroleum and Natural Gas Systems source

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[8] The implementing regulations of the Petroleum and Natural Gas Systems source category of the GHGRP are located at 40 CFR Part 98 Subpart W.

[9] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed a specialized facility definition for onshore production. For onshore production, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

category is required to submit annual reports if total emissions are 25,000 metric tons carbon dioxide equivalent (CO_2e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities have a choice of calculation methods for an emission source.

Under the GHGRP, facilities report associated gas vented and flared emissions. Vented emissions are calculated based on GOR and the volume of oil produced and flared emissions using a continuous flow measurement device or engineering calculation. For 2012, 171 facilities reported associated gas vented and flared emissions to the GHGRP. Total reported methane emissions were 89,535 MT.

4.2 FLARING UP: North Dakota Natural Gas Flaring More Than Doubles in Two Years (Flaring Up) (CERES, 2013)

The Flaring Up report discusses the increase in North Dakota's oil and gas production from the Bakken formation between 2007 and mid-2013, the increased flaring of associated gas, and the potential value of NGL lost as a result of flaring. The report presents some associated gas production and flaring data that the authors derive from the gas production and flaring data reported by the North Dakota Industrial Commission (NDIC), Department of Mineral Resources. The Commission defines associated gas to be all natural gas and all other fluid hydrocarbons not defined as oil. Oil is defined by the Commission to be all crude petroleum oil and other hydrocarbons, regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas[10].

This Flaring Up report indicates that of the wells that are flaring the associated gas, approximately 55% are wells are not connected to a gas gathering system, while 45% are wells that are already connected. In addition, the report states that in May of 2013, 266,000 Mcf per day was flared, which represents nearly 30% of the gas produced (CERES, 2013). Percent flaring is currently reported by the NDIC while the connection data is tracked by the North Dakota

[10] North Dakota Century Code, Section I, Chapter 38-08 Control of Gas & Oil Resources, Section 38-08-02.

Pipeline Authority. The report concludes that the reason for the flaring of the associated gas is lack of pipeline infrastructure, lack of capacity and lack of compression infrastructure.

The data and information in this report is useful for discussion on the relative percentages of gas emissions being flared. The data, however, are specific to the Bakken, a formation that possesses unique characteristics both with regard to reservoir and formation characteristics, gas composition and the lack of infrastructure due to rapid development of the industry in the area.

5.0 AVAILABLE EMISSION MITIGATION TECHNIQUES

Two mitigation techniques were considered that have been proven in practice and in studies to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would otherwise be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the efficacy at reducing emissions and costs for their application for a representative well. Combustion control for control of associated gas emissions (e.g., flaring) has been demonstrated as effective in the industry. However, flaring results in the destruction of a valuable resource and, as such, alternate uses for uncaptured/sold associated gas have been the subject of several studies with respect to new emerging technologies.

5.1 Reduced Emission Completions (REC)

5.1.1 Description

Reduced emissions completions are defined for the purposes of this paper as:

> A well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other

useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced emission completions, also referred to as “green” completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. It is the EPA’s understanding that the additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps and a gas dehydrator. In many cases, portable equipment used for RECs operates in tandem with the permanent equipment that will remain after well drilling is completed (EC/R, 2010b). In other instances, permanent equipment is designed (e.g., oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs because technical barriers vary from well to well. Three main limitations include the following:

- Proximity of pipelines. For certain wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields.

- Pressure of produced gas. Based on experience using RECs at gas wells, the EPA understands that during each stage of the completion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line.

- Inert gas concentration. Based on experience using RECs at gas wells, if the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

5.1.2 Effectiveness

Based on data available on RECs use at gas wells, the emission reductions from RECs can vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on the results reported by four different Natural Gas STAR Partners who performed RECs primarily at natural gas wells, a representative control efficiency of 90% for RECs was estimated. The companies provided both recovered and total produced gas, allowing for the calculation of the percentage of the total gas which was recovered. This estimate was based on data for more than 12,000 well completions (ICF, 2011). Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95% reduction in emissions. Additionally, both wells that co-produced oil and gas and were controlled with a REC in the UT Austin study achieved greater than 98% reduction in methane emissions.

5.1.3 Cost

The discussion of cost in this section is based on the EPA's experience with RECs at gas wells. It is the EPA's understanding that the same equipment is used for RECs at gas wells and co-producing oil wells. All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

The average cost of RECs was obtained from data shown in the Natural Gas STAR Lessons Learned document titled "Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells" (U.S. EPA, 2011a). The impacts calculations use the cost per day for gas capture and the duration of gas capture along with a setup/takedown/transport cost and a flare cost to represent the total cost. The cost is then annualized across the time horizon under study.

Costs of performing a REC are projected to be between $700 and $6,500 per day (U.S. EPA, 2011a). This cost range is the incremental cost of performing a REC over a completion without a REC, where typically the gas is vented or combusted because there is an absence of REC equipment. These cost estimates are based on the state of the industry in 2006 (adjusted to 2008 U.S. dollars). [11] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three-phase separator, are already found onsite and are of suitable design and capacity for use during flowback.
- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought onsite and then relocated after the completion.

The average of the above data results in an average incremental cost for a REC of $4,146 per day (2008 dollars).[12] The total cost of the REC depends on the length of the flowback period, and thus the length of the completion process. For example, if the completion takes 7 days then the total cost would be $29,022, and if the completion takes 3 days then the total cost would be $12,438 versus an uncontrolled completion. These costs would be mitigated by the value of the captured gas. The extent of this cost mitigation would depend on the price of the gas and the quantity that was captured during the REC.

[11] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

[12] The average incremental cost for a REC was calculated by averaging $806 per day and $7,486 per day (2008 dollars). While the average estimated cost per day is presented here, it is likely that the cost that is paid by a well operator will be the low incremental cost if key pieces of equipment are already present onsite or the high incremental cost if this equipment is not present onsite, and not the average of these two estimates.

5.1.4 Prevalence of Use at Oil Wells

The UT Austin study found that some co-producing oil wells are conducting RECs. It is the EPA's understanding that in some cases RECs are currently used on co-producing oil wells if pipeline infrastructure is available.

5.2 Completion Combustion Devices

5.2.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in gas streams (U.S. EPA, 1991). Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion devices can normally handle fluctuations in concentration, flow rate, heating value, and inert species content (U.S. EPA, Flares). These devices can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Completion combustion devices provide a means of minimizing vented gas during a well completion and are generally preferable to venting, due to reduced air emissions.

5.2.2 Effectiveness

Completion combustion devices can be expected to achieve 95% emission reduction efficiency, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it may be more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. If a completion combustion device has a continuous ignition source with an independent external fuel supply, then it is assumed to achieve an average of 95% control over the entire flowback period (U.S. EPA, 2012b).

5.2.3 Cost

An analysis of costs provided by industry for enclosed combustors was conducted by the EPA for the FBIR FIP. In addition, the State of Colorado recently completed an analysis of industry provided combustor cost data and updated their cost estimates for enclosed combustors (CDPE, 2013). Table 5-1 summarizes the data provided from each of the sources with the average cost for an enclosed combustor across these sources being $18,092. It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. Also noted in the table is the most recent combustor cost used for reconsideration of control options for storage vessels under subpart OOOO.

As with RECs, because completion combustion devices are purchased for these one-time events, annual costs were assumed to be equal to the capital costs. However, multiple completions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. Costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. This approach may overestimate the true cost of combustion devices per well completion or recompletion.

5.2.4 Prevalence of Use at Oil Wells

The UT Austin study found that some co-producing oil wells are using completion combustion devices to reduce emissions. It is the EPA's understanding that the most common approach to reducing emissions from hydraulically fractured oil well completions is the use of a completion combustion device.

Table 5-1. Analysis of Industry Provided Enclosed Combustor Cost

Cost Parameter	Industry Provided Data						EPA Estimate in Subpart OOOO	
	FBIR				CDPHE			CDHPE
	EOG	XTO	Enerplus	QEP		Average of quotes	Original Data Used	Adjusted Data Used[a]
Annualized Capital Cost	$5,268	$6,727	$6,116	$6,763	$3,569	$6,281	$3,546	$4,746
Other Annual Costs								
Pilot Fuel	NR	NR	NR	NR	$636		$2,078	$2,144
Operating Labor (includes management)	NR	NR	NR	NR	$10,670		$10,670	$11,012
Maintenance	NR	NR	NR	NR	$2,206		$2,190	$2,260
Data Management	NR	NR	NR	NR	$1,000		$1,095	$1,130
Total Other Annual Costs (combustor)[c]	$1,500	$23,250	$6,289	$8,500	$14,512	$10,810	$16,033	$16,546
Other Annual Costs (continuous pilot)[c]	$1,000	NR	NR	NR	included in combustor costs[b]	$1,000	included in combustor costs[b]	included in combustor costs[c]
Total Annual Costs	**$7,768**	**$29,977**	**$12,405**	**$15,263**	**$18,081**	**$18,092**	**$19,580**	**$21,292**

NR = Not reported, FBIR = Fort Berthold Indian Reservation, CDPHE = Colorado Department of Public Health and Environment, EOG = EOG Resources, XTO = XTO Energy Inc. , QEP = QEP Energy Co
Cost data in 2012 dollars
a - Cost data for 40 CFR part 60, subpart OOOO updated to reflect more current cost year and equipment life (industry comments indicated a 10-year equipment life as opposed to 15 years)
b - Data used for subpart OOOO included a cost for an auto ignition system, surveillance system, VRU system, and freight and installation
c - Quotes received for FBIR FIP did not specify what was included in other annual costs.

5.3 Emerging Control Technologies for Control of Associated Gas

Several types of alternative use technologies are being investigated both by industry and regulators for use of associated gas.

The most prominent alternative technologies being investigated to address associated gas are liquefaction of natural gas, NGL recovery, gas reinjection, and electricity generation.

According to the Schlumberger Oilfield Glossary, "liquefied natural gas refers to natural gas, mainly methane and ethane, which has been liquefied at cryogenic temperatures. This process occurs at an extremely low temperature and a pressure near the atmospheric pressure. When a gas pipeline is not available to transport gas to a marketplace, such as in a jungle or certain remote regions offshore, the gas may be chilled and converted to liquefied natural gas (a liquid) to transport and sell it. The term is commonly abbreviated as LNG." Research is being conducted on the economic and technical feasibility of liquefaction of natural gas as a means to realize the full potential of the U.S. natural gas resources, particularly with respect to the potential of U.S. exports of LNG. However, available information indicates that this technology is typically implemented on a macro scale, requiring installation of large facilities and transportation infrastructure. Because the EPA is unaware of existing studies or further information on liquefaction of gas at the wellhead, liquefaction of natural gas is not discussed further in this paper.

Cost information is summarized to the extent that this information is readily available. In many cases, available literature does not provide cost information as the economics of the technology are still being researched.

5.3.1 Natural Gas Liquids (NGL) Recovery

Natural gas liquids are defined as "components of natural gas that are liquid at surface in field facilities or in gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied. The term is commonly abbreviated as NGL."[13]

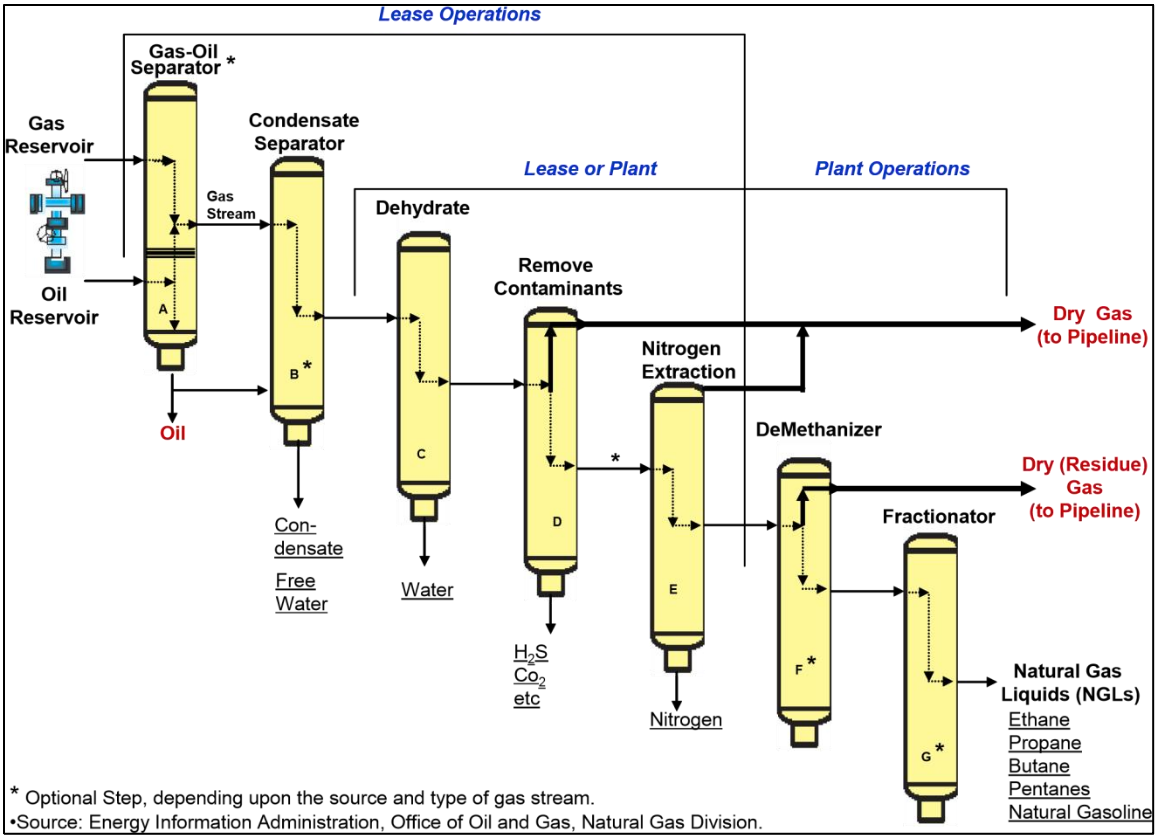
Associated gas from the Bakken formation has been termed "rich" gas, which is defined as naturally containing heavier hydrocarbons than a "lean" gas. Its liquid content adds important economic value to developments containing this type of fluid. Therefore, the value of the NGLs in the associated gas from the Bakken formation has been the subject of several studies, particularly with the concerns raised based by the rapid development of Bakken and increased flaring of associated gas. As would be expected, most of the recent studies related to NGL recovery are based on the Bakken formation.

One of these studies is the "End-Use Technology Study – An Assessment of Alternative Uses for Associated Gas" conducted by the Energy & Environmental Research Center (EERC) of the University of North Dakota (EERC, 2013). The study was conducted based on associated gas production in December 2011 and was published in 2012. This study provides an evaluation of alternative technologies and their associated costs and benefits. In particular, the study looks at NGL recovery, as a standalone operation for both recovery of salable NGLs and as a pretreatment of the associated gas for use in other local operations such as power generation.

To understand NGL recovery, the typical natural gas processing that occurs at or near the wellhead will be reviewed. Liquids and condensates (water and oil) are separated from the "wet" gas. The condensates are transported via truck or pipeline for further processing at a refinery or gas processing plant. The minimally processed wellhead natural gas is then transported to a gas-processing plant via pipeline. There, the gas is processed to remove more water, separate out NGL, and remove sulfur and carbon dioxide in preparation for release to the sales distribution system. Figure 5-1 summarizes generalized natural gas processing.

[13] From Schlumberger Oilfield Glossary available at http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=natural+gas++liquids

Figure 5-1. Generalized Natural Gas Processing Schematic



Source: U.S. EIA, 2006.

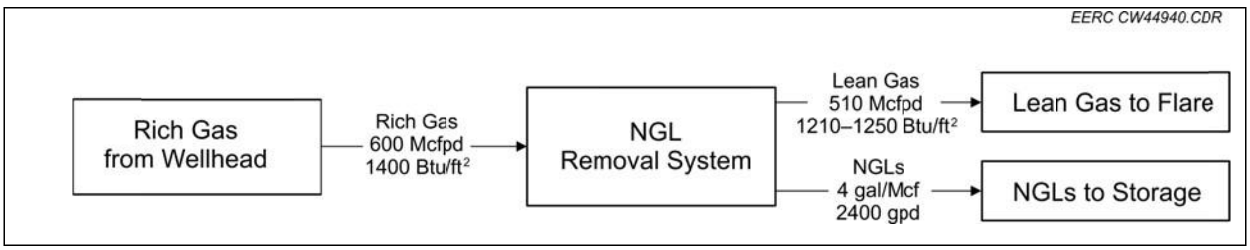
Because of the relatively high value of NGL products produced, recovery technologies have been developed both for large and small scale gas-processing applications. There are generally three approaches used in these technologies:

- Control of temperature and pressure to achieve condensation of NGLs
- Separation of heavier NGLs from lighter gas with pressurized membrane separation systems
- Physical/chemical adsorption/absorption

The typical NGL recovery technologies used are turboexpander with demethanizer, Joule-Thomson (JT) low pressure separation membranes, absorption (Refrigerated Lean Oil Separation, RLOS), adsorption using active carbon or molecular sieve, and Twister Supersonic Gas Low Temperature Separation Dew Pointing Process. For the purposes of this paper, the specifics of these technologies are not discussed; rather, the focus will be on the overall outcome and potential costs for small scale implementation at the well head for addressing associated gas.

The EERC study included a case study for a small scale NGL Recovery process at a well head. The case study evaluated the potential for deploying small scale NGL recovery systems as an interim practice to flaring associated gas while gathering lines and infrastructure were being installed or upgraded. These systems would allow the most valuable hydrocarbon portion of the gas to be captured and marketed. The leaner gas resulting could be used onsite for power generation or transported as a compressed gas. Alternatively, the leaner gas could continue to be flared. Figure 5-2 depicts the NGL Removal system flow diagram.

Figure 5-2. Natural Gas Liquids (NGL) Removal System Flow Diagram



Source: Figure 22, EERC, 2013

According to the EERC study, 10 to 12 gallons of NGL/Mcf of associated gas is present in many producing Bakken wells. At an estimated NGL removal rate of 4 gallons/Mcf (from 1000 Mcf/day of rich gas), the daily production of NGLs would be approximately 4,000 gallons of NGLs per day (EERC, 2013). The study also states that at least at the current natural gas price, the NGLs make up a majority of the economic value of the rich gas. An evaluation of a simplified model on small-scale NGL recovery was developed based on a JT-based technology. The NGL removal system evaluation assumes the parameters shown in Table 5-2.

Table 5-2. Assumptions for NGL Recovery Case (Table 9, EERC, 2013)

Parameter	Assumed Value
Rich Gas Flow Rate from the Wellhead, average	300 Mcf/day
Rich Gas Flow Rate Processed, economic cutoff	600 Mcf/day
Rich Gas Flow Rate, design flow	1000 Mcf/day
Rich Gas Heat Content	1400 Btu/ft^3
Rich Gas Price (cost) at the Wellhead	$0.00/Mcf
Volume of NGLs Existing in Rich Gas	10–12 gallons/Mcf
NGL Price, value	$1.00/gallon
Lean Gas Flow Rate from NGL Removal System	85% of rich gas flow rate
Lean Gas Heat Content	1210–1250 Btu/ft^3
Lean Gas Price, value	$2.00/Mcf

The EERC study estimated capital and annual costs for the NGL removal system. Operating and maintenance (O&M) costs were assumed to be 10% of the total capital cost. Revenue calculations were based on NGL sales only at $1/gallon and a recovery rate of 4 gallons/Mcf. In this scenario, it has been assumed that residue gas is flared (EERC, 2013). Table 5-3, derived from Table 10 of the study, summaries the cost for the small sale NGL recovery system.

Table 5-3. Summary of NGL Removal System Costs (Table 10, EERC)

Description	Capital Cost	Annual O&M Cost
NGL Removal System, 300 Mcfd rich gas	$2,500,000	$250,000
NGL Removal System, 600 Mcfd rich gas	$2,500,000	$250,000
NGL Removal System, 1000 Mcfd rich gas	$2,500,000	$250,000

Mcfd = One thousand standard cubic feet per day.

The EERC study concluded that the technical aspects of NGL recovery are fairly straight forward; however, the business aspects are much more complicated, particularly with respect to NGL product supply chain and contractual considerations. Further, the study concluded that NGL recovery would be most economical at wells flaring larger quantities of gas immediately after production begins. Other attributes that would be important for the economic feasibility of the NGL recovery system would be that the systems are mobile and easily mobilized, and that infrastructure with respect to truing of NGL production is available.

5.3.2 Natural Gas Reinjection

Schlumberger's Oilfield Glossary defines gas injection as "a reservoir maintenance or secondary recovery method that uses injected gas to supplement the pressure in an oil reservoir or field. In most cases, a field will incorporate a planned distribution of gas-injection wells to maintain reservoir pressure and effect an efficient sweep of recoverable liquids."[14]

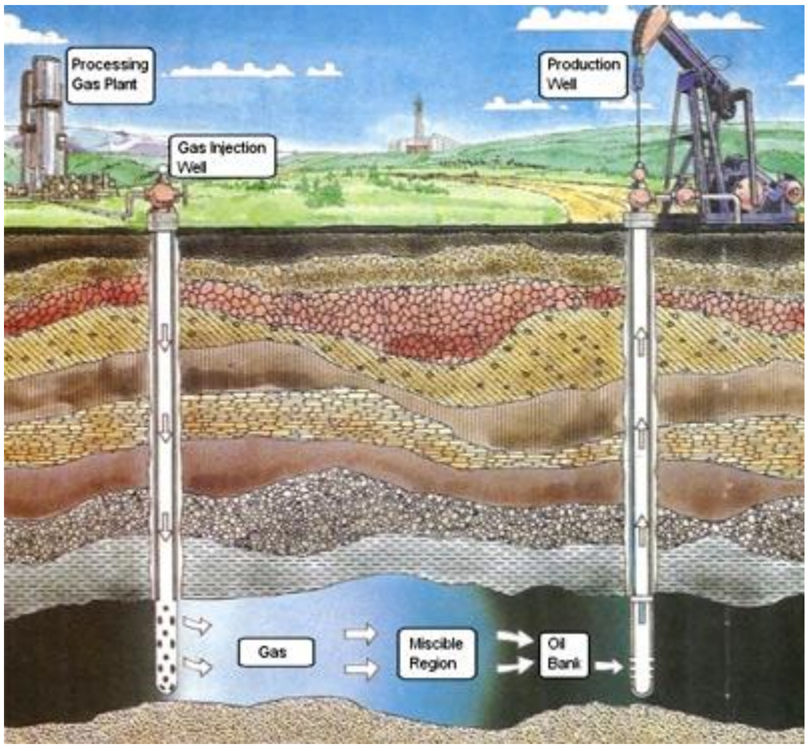
The industry has employed production methods to increase production, which are termed enhanced oil recovery (EOR) or improved oil recovery (IOR) (Rigzone, 2014). These methods are generally considered to be tertiary methods employed after waterflooding or pressure maintenance. The practice involves injecting gas into the gas cap of the formation and boosting the depleted pressure in the formation with systematically placed injection wells throughout the field. The pressure maintenance methods maybe employed at the start of production or introduced after the production has started to lessen. The reinjection of natural gas is the use of associated gas at the same oilfield to accomplish the goals of gas injection as defined above. The increase in the pressure within the reservoir helps to induce the flow of crude oil. After the crude has been pumped out, the natural gas is once again recovered.

Natural gas injection is also referred to as cycling. Cycling is used to prevent condensate from separating from the dry gas in the reservoir due to a drop in reservoir pressure. The condensate liquids block the pores within the reservoir, making extraction practically impossible. The NGL are stripped from the gas on the surface after it has been produced, and the dry gas is

[14] Schlumberger Oilfield Glossary, available at http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=gas+injection

then re-injected into the reservoirs through injection wells. Again, this helps to maintain pressure in the reservoir while also preventing the separation within the hydrocarbon (Rigzone, 2014). Figure 5-3 illustrates the relationship between the gas injection well and the production well.

Figure 5-3. Gas Injection and Production Well

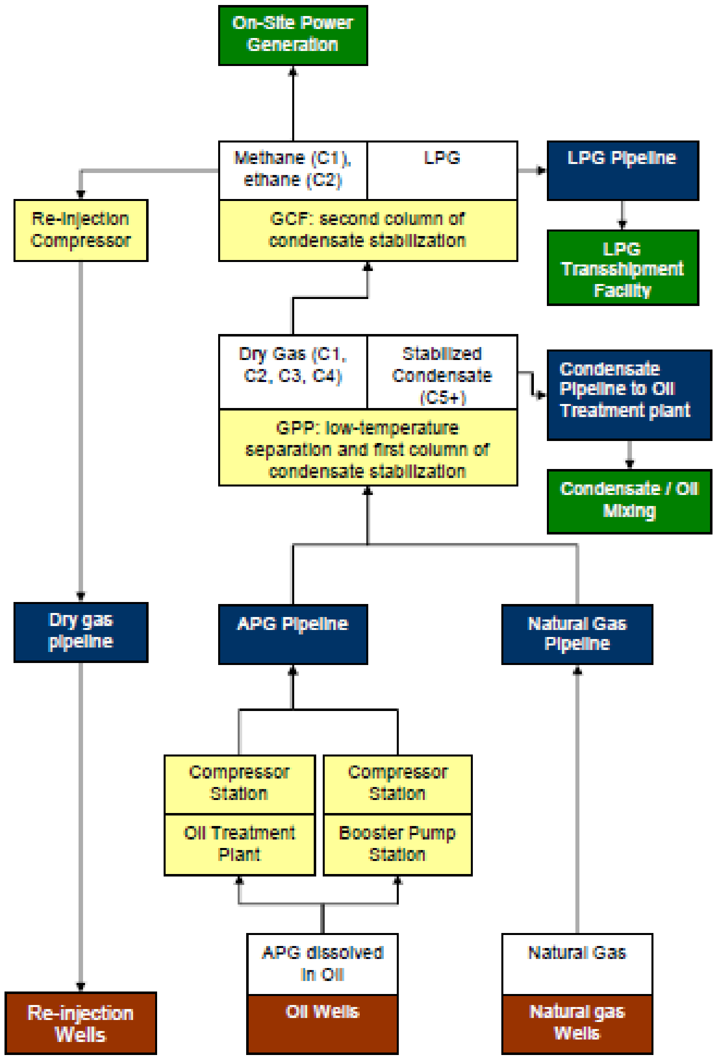


Source: Rigzone, 2014

In the scenarios that were found in available literature, the dry gas is also used as fuel onsite for the generators that power the reinjection pumps. Therefore, the costs associated with the process are mainly initial capital costs. No published information was obtained on the capital and annual costs for these operations.

Figure 5-4 presents a fully implemented gas injection project scheme. In this scheme, associated gas from an oil well (or natural gas from a gas well) is processed through a gas cycling facility (GCF) where recoverable NGLs are separated from methane and the resulting methane is either used for onsite power generation or re-injected in to the formation.

Figure 5-4. Gas Cycling Facility Project Flow



The literature that was reviewed evaluated gas reinjection projects only from the perspective of an enhanced oil recovery opportunity and did not specifically discuss the quantity or percentage of associated gas emissions that were eliminated through the process. The EPA is not aware of literature that discusses the efficacy of mitigating associated gas emissions using the natural gas reinjection process. The efficacy would be highly dependent on many factors, which include the composition value of the gas and the availability of transmission infrastructure. Further, because the use of this process to reduce associated gas emissions in conjunction with oil recovery is an emerging technology, the prevalence of use in the industry and estimated cost to implement the process is unknown to the EPA.

5.5.3 Electricity Generation for Use Onsite

As discussed above, associated gas can be used for generation of electrical power to be used onsite. The EERC study stated that power generation technologies would need to be designed to match the variable wellhead gas flow rates and gas quality, and would need to be constructed for mobility. The EERC study discussed previously also looked at options for use of associated gas for power generation. The EERC study included an evaluation of several technologies fired by natural gas both for grid support (i.e., power generation for direct delivery onto the electric grid) and local power (i.e., power generation for local use with excess generation, if any, sent to the electrical grid). This study provides one of the most comprehensive and recent evaluations of the economics of use of associated gas for electric generation. Therefore, the case study results of this study are used to discuss the cost of this technology for this paper.

Although grid support is potentially a viable use for this gas, it is not considered to be an emissions reduction technology for the purposes of this paper. Grid support requires an infrastructure similar in scope as that needed to bring gas to market. The focus of this section of the paper is on the venting or flaring of associated gas due to the lack of infrastructure to bring it to market. It is unlikely that a well site that is lacking pipeline infrastructure would have access to the necessary infrastructure to provide grid support. Therefore, the focus here is on the use of the gas at the local level, either directly at the wellpad or in an immediate oilfield region to support local activities. The benefits of using associated gas to provide electricity for these activities are both reducing the quantity of gas vented and reducing the quantity of other types of fuel used (e.g., diesel).

The EERC study considered a local power project to be wellhead gas (with limited cleanup) being piped to an electrical generator that produces electricity which is first used to power local consumption (e.g., well pad, group of wells, or an oilfield) with any excess electricity put on the electrical grid for distribution by the local utility to its customers. These projects can range widely in scale, depending on the goal of the project (i.e., satisfy only local load, satisfy local load with minimal excess generation, or satisfy local load with significant excess generation). The study evaluated two power generation scenarios: reciprocating engine and a microturbine.

The first step in using associated gas for electric generation is removal of NGLs from the rich gas. Removal of the NGLs significantly increases the performance of the genset and reduces the loss of resource (when flaring is necessary). According to the EERC study, removal of NGLs such as butane and some propane could be accomplished using a low temperature separation process. The study found that small, modular configurations of these types of systems are not widely available. The estimated capital cost for the NGL removal and storage system is $2,500,000. This capital cost includes the necessary compression to take the rich gas from the heater/treater at 35 psi up to 200 - 1000 psi delivered to the NGL removal system as well as the cost for four 400-bbl NGL storage tanks (EERC, 2013). The study authors considered NGL recovery a valuable first step; however, they also stated that it was not necessary in all circumstances.

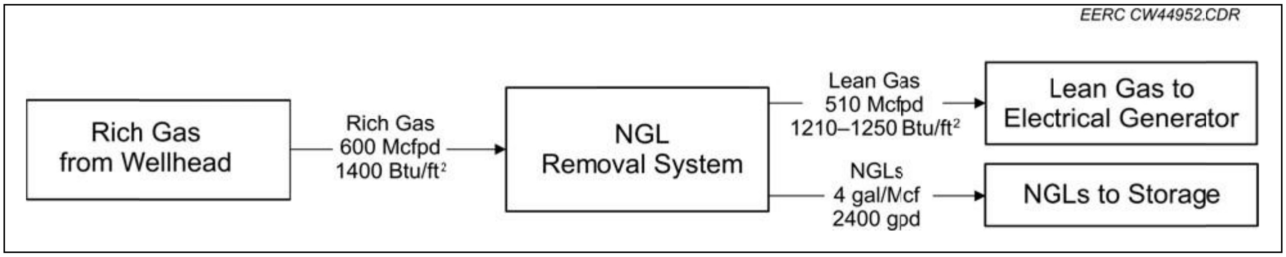
The study made certain assumptions about the flow of associated gas from the wellhead and fuel consumption of the respective electrical generator for the case study. Table 5-4 summarizes the assumed wellhead gas flow for the case study. Figure 5-5 shows a block flow diagram of an example NGL removal system.

Table 5-4. Summary of Wellhead Gas Flow and Product Volume Assumptions

Scenario	Rich Gas Flow, Mcf/day	NGLs Produced, gallons/day	Lean Gas Produced, Mcf/day
Reciprocating Engine	600	2,400	510
Microturbine	600	2,400	510

Source Table 33, EERC 2013

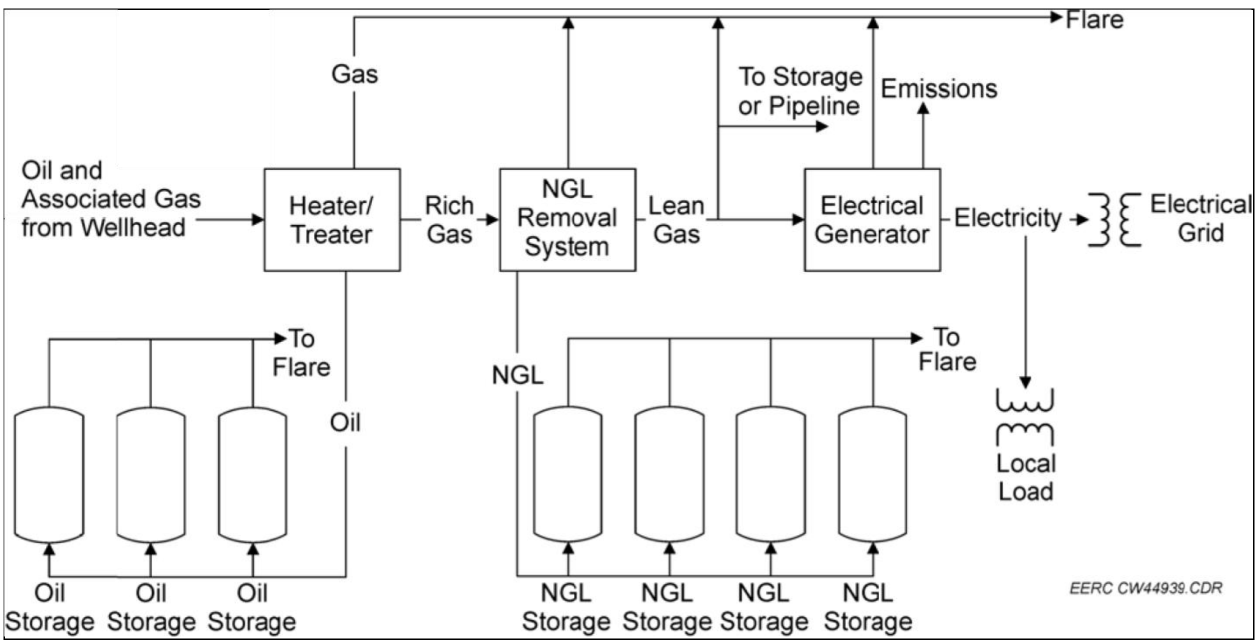
Figure 5-5. NGL Removal System Block Flow Diagram



Source Figure 32, EERC 2013

For the case study, the authors targeted a power production scenario of 1 MW for the reciprocating engine and 200 kW for the microturbine. Both scenarios used the same NGL removal system prior to introduction of the rich gas to the generator. Figure 5-6 depicts the process flow diagram for the local power generation scenario.

Figure 5-6. Process Flow Diagram, Local Power Generation Scenario



Source: Figure 33, EERC, 2013

For the reciprocating engine scenario, vendor provided costs for a 250-kW natural gas fired reciprocating engine genset was $200,000. The study estimated the annual O&M cost was assumed to be 10% of the capital cost. The costs for this scenario are summarized in Table 5-5.

Table 5-5. Total Cost Summary - Reciprocating Engine Scenario

	Capital Cost	Annual Cost
NGL Removal and Storage System	$2,500,000	$250,000
Electrical Generator System	$200,000	$20,000
All Other Infrastructure	$500,000	
Total Capital Cost	**$3,200,000**	**$270,000**

Source Table 38, EERC 2013

For the microturbine scenario, the authors chose to analyze a four, 65 kW microturbine package rated to provide approximately 195 kW of power. This scenario also involved the removal of NGLs prior to delivery of gas to the microturbine and the use of generated electricity to satisfy local electrical demand, with the excess electricity delivered to the grid. The authors noted that the volume of gas generated from the wellhead(s) will determine the size of the system needed and that a range of generation scales should be considered for optimum performance. The process flow for this scenario is the same as shown above in Figure 5-6.

The NGL removal system is likely to be much larger in processing capacity than the electrical generation system. Generally, the NGL removal system will be most economical only at the higher-gas-producing wells. The microturbine package evaluated consumed less than 100 Mcf/day, which meant that excess gas would either need to be flared or the project must be designed to store the excess gas for sale to the pipeline. In the scenarios described here, the authors assumed that the excess lean gas is sold.

For the microturbine system analyzed, the vendors offered a factory protection plan (FPP) that covers all scheduled and unscheduled maintenance of the system as well as parts, including an overhaul or turbine replacement at 40,000 hours of operation. The FPP “locks in” the annual O&M cost of the system and, in both scenarios presented below, it is assumed that the FPP is purchased (EERC, 2013). Table 5-6 summarizes the capital and annual O&M costs for the microturbine system, as well as the NGL recovery system discussed above.

Table 5-6. Total Cost Summary - Microturbine Scenario (Four 65-kW)

	Capital Cost	**Annual Cost**
NGL Removal and Storage System	$2,500,000	$250,000
Electrical Generator System	$383,200	$33,640
All Other Infrastructure	$500,000	
Total Capital Cost	**$3,382,200**	**$283,640**

Source: Table 41, EERC, 2013.

The study authors also evaluated revenue potential for electricity sent to the grid as an offset to the costs summarized above. Their analysis indicated that based on cost (discussed above) and their revenue assumptions, both scenarios provided a simple payback of 3 years or less. However, given the substantial upfront capital costs of these options, these options may not be preferable to building the necessary pipeline infrastructure to take the gas to market.

In addition to the electric generation potential for associated gas, the study also discussed the use of wellhead gas as a fuel for drilling operations. The authors indicated that the EERC is working with Continental Resources, ECO-AFS, Altronics, and Butler Caterpillar to conduct a detailed study and field demonstration of the GTI Bi-Fuel System. Within that task, the EERC conducted a series of tests at the EERC using a simulated Bakken gas designed to test the operational limits of fuel quality and diesel fuel replacement while monitoring engine performance and emissions. The authors indicated that the Bi-Fuel System is an aftermarket addition to the system allowing natural gas to the air intake, and the engine performance is unaltered from the diesel operation. This system, as the name implies, could be used on either fuel without requiring any alterations.

According to the study report, total installed capital cost for the Bi-Fuel System ranges from $200,000 to $300,000 (EERC, 2013). Other costs that would be incurred would be those for piping wellhead gas to the engine building. The study did not include those costs because they can be highly variable depending on the distance to the nearest gas source and gas lease terms.

The study reports that ECO-AFS had recently installed several Bi-Fuel Systems on rigs in the Williston Basin and that early data suggest that diesel fuel savings of approximately $1 to $1.5 million can be achieved annually. Under typical conditions, operators can expect to achieve diesel replacement of 40% - 60% at optimal engine loads of 40% - 50% (EERC, 2013).

The EERC study noted that there are a number of other potential natural gas uses related to oil production and operations that could take advantage of rich gas on a well site. Those would include:

- Heating of drilling fluids during winter months (replacing the diesel or propane fuel used currently)
- Providing power for hydraulic fracturing operations decreasing reliance on diesel fuel (i.e., by using Bi-fuel systems)
- Providing fuel for workover rigs (if the rig is equipped with a separate generator)

6.0 SUMMARY

As discussed in the previous sections, the EPA used the body of knowledge presented in this paper to summarize its understanding of emissions characterization and potential emissions mitigation techniques for oil well completions and associated gas. From that body of knowledge, the following statements summarize the EPA's understanding of the state of the industry with respect to these sources of emissions:

- Available estimates of uncontrolled emissions from hydraulically fractured oil well completions are presented below:

Study	Average Uncontrolled VOC Emissions (Tons/Completion)	Average Uncontrolled Methane Emissions (Tons/Completion)
Fort Berthold Federal Implementation Plan	37	N/A
ERG/ECR Analysis of HPDI® Data (7 day flowback period)	20.2	24
ERG/ECR Analysis of HPDI® Data (3 day flowback period)	6.4	7.7
EDF/Stratus Analysis of HPDI® Data (Eagle Ford)	N/A	27.2
EDF/Stratus Analysis of HPDI® Data (Wattenberg)	N/A	10.5
EDF/Stratus Analysis of HPDI® Data (Bakken)	N/A	19.8
Measurements of Methane Emissions at Natural Gas Production Sites in the United States	N/A	213
Methane Leaks from North American Natural Gas Systems (Eagle Ford)	N/A	90.9
Methane Leaks from North American Natural Gas Systems (Bakken)	N/A	31.1
Methane Leaks from North American Natural Gas Systems (Permian)	N/A	31.2

- Limited information is available on uncontrolled emissions from hydraulically fractured oil well recompletions, and controlled emission factors for hydraulically fractured oil well completions and recompletions.
- National level estimates of uncontrolled methane emissions from hydraulically fractured oil well completions range from 44,306 tons per year (ERG/ECR) to 247,000 tons per year (EDF/Stratus analysis).
- One study (ERG/ECR) estimated nationwide uncontrolled VOC emissions from hydraulically fractured oil well completion to be 116,230 tons per year assuming a 7-day flowback period and 36,825 tons per year assuming a 3-day flowback period.
- There is some data that shows (Allen et. al.) that RECs, in certain situations, can be an effective emissions control technique for oil well completions when gas is co-produced.

However, there may be a combination of well pressure and gas content below which RECs are not technically feasible at co-producing oil wells.

- Some oil well completions are controlled using RECs; however, national data on the number of completions that are controlled using a REC are not available. It is the EPA's understanding that most oil well completion emissions are controlled with combustion; however, data on an average percentage are not available. Likewise, data are not available on the percentage of oil wells nation-wide that vent completion emissions to the atmosphere.
- Other gas conserving technologies are being investigated for use in completions and for control of associated gas emissions. These include gas reinjection, NGL recovery and use of the gas for power generation for local use. Some studies have evaluated the economics of some of these technologies and determined, in some cases, they can result in net savings to the operator depending on the value of the recovered gas or liquids or the value of the power generated. However, some barriers exist with respect to technology availability and application of the technology to varying scales of oil well gas production. In addition, costs vary for implementing some of these technologies.

7.0 CHARGE QUESTIONS FOR REVIEWERS

1. Please comment on the national estimates and per well estimates of methane and VOC emissions from hydraulically fractured oil well completions presented in this paper. Are there factors that influence emissions from hydraulically fractured oil well completions that were not discussed in this paper?

2. Most available information on national and per well estimates of emissions is on uncontrolled emissions. What information is available for emissions, or what methods can be used to estimate net emissions from uncontrolled emissions data, at a national and/or at a per well level?

3. Are further sources of information available on VOC or methane emissions from hydraulically fractured oil well completions beyond those described in this paper?

4. Please comment on the various approaches to estimating completion emissions from hydraulically fractured oil wells in this paper.
   - Is it appropriate to estimate average uncontrolled oil well completion emissions by using the annual average daily gas production during the first year and multiplying that value by the duration of the average flowback period?
   - Is it appropriate to estimate average uncontrolled oil well completion emissions using "Initial Gas Production," as reported in DI Desktop, and multiplying by the flowback period?
   - Is it appropriate to estimate average uncontrolled oil well completion emissions by increasing emissions linearly over the first nine days until the peak rate is reached (normally estimated using the production during the first month converted to a daily rate of production)?
   - Is the use of a 3-day or 7-day flowback period for hydraulically fractured oil wells appropriate?
5. Please discuss other methodologies or data sources that you believe would be appropriate for estimating hydraulically fractured oil well completion emissions.

6. Please comment on the methodologies and data sources that you believe would be appropriate to estimate the rate of recompletions of hydraulically fractured oil wells. Can data on recompletions be used that does not differentiate between conventional oil wells and hydraulically fractured oil wells be reasonably used to estimate this rate? For example, in the GHG Inventory, a workover rate of 6.5% is applied to all oil wells to estimate the number of workovers in a given year, and in the ERG/ECR analysis above a rate of 0.5% is developed based on both wells with and without hydraulic fracturing. Would these rates apply to hydraulically fractured oil wells? For hydraulically fractured gas wells, the GHG Inventory uses a refracture rate of 1%. Would this rate be appropriate for hydraulically fractured oil wells?

7. Please comment on the feasibility of the use of RECs or completion combustion devices during hydraulically fractured oil well completion operations. Please be specific to the types of wells where these technologies or processes are feasible. Some characteristics that should be considered in your comments are well pressure, gas content of flowback, gas to oil ratio

(GOR) of the well, and access to infrastructure. If there are additional factors, please discuss those. For example, the Colorado Oil and Gas Conservation Commission requires RECs only on "oil and gas wells where reservoir pressure, formation productivity and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater."[15]

8. Please comment on the costs for the use of RECs or completion combustion devices to control emissions from hydraulically fractured oil well completions.

9. Please comment on the emission reductions that RECs and completion combustion devices achieve when used to control emissions from hydraulically fractured oil well completions.

10. Please comment on the prevalence of the use of RECs or completion combustion devices during hydraulically fractured oil well completion and recompletion operations. Are you aware of any data sources that would enable estimating the prevalence of these technologies nationally?

11. Did the EPA correctly identify all the available technologies for reducing gas emissions from hydraulically fractured oil well completions or are there others?

12. Please comment on estimates of associated gas emissions in this paper, and on other available information that would enable estimation of associated gas emissions from hydraulically fractured oil wells at the national- and the well-level.

13. Please comment on availability of pipeline infrastructure in hydraulically fractured oil formations. Do all tight oil plays (e.g., the Permian Basin and the Denver-Julesberg Basin) have a similar lack of infrastructure that results in the flaring or venting of associated gas?

14. Did the EPA correctly identify all the available technologies for reducing associated gas emissions from hydraulically fractured oil wells or are there others? Please comment on the

[15] Colorado Department of Natural Resources: Oil and Gas Conservation Commission Rule 805.b(3)A. (http://cogcc.state.co.us/)

costs of these technologies when used for controlling associated gas emissions from hydraulically fractured oil wells. Please comment on the emissions reductions achieved when these technologies are used for controlling associated gas emissions from hydraulically fractured oil wells.

15. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from hydraulically fractured oil well completions and associated gas and available options for increased product recovery and emission reductions?

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Appendix A

(ERG, 2013)

<u>Memorandum (Draft)</u>:

Environmental Research Group, Inc.

Hydraulically Fractured Oil Well Completions.

October 24, 2013

DRAFT MEMORANDUM

TO: David Hendricks, EC/R Incorporated

FROM: Mike Pring, Eastern Research Group, Inc. (ERG)

Regi Oommen, ERG

DATE: October 24, 2013

SUBJECT: Hydraulically Fractured Oil Well Completions

Eastern Research Group, Inc. (ERG) is currently under contract with EC/R Incorporated to provide technical support under EC/R Work Assignment #1-11 with U.S. EPA. This memorandum describes ERG's findings relative to Task 2 of the support effort. Specifically, under this task ERG:

- Identified wells which were hydraulically fractured in 2011;
- Determined which of the hydraulically fractured wells completed in 2011 were oil wells;
- Estimated daily associated gas production from the hydraulically fractured oil wells; and
- Provided a summary of this information at the national and county level (in Excel spreadsheet format).

Wells Hydraulically Fractured in 2011

Starting with the most recent analysis and files delivered by ERG to the U.S. EPA Office of Compliance, ERG queried DI Desktop, a production database maintained by DrillingInfo, Inc.

covering U.S. oil and natural gas wells, to identify hydraulically fractured oil and gas well completions performed in 2011. This was accomplished using a two-step process:

- Identification of wells completed in 2011;
- Identification of wells completed using hydraulic fracturing.

Wells completed in 2011 were identified as those wells meeting one of the following criteria:

- The DI Desktop data for the well indicated it was completed in 2011; or
- The DI Desktop data for the well indicated the well 1st produced in 2011.

While the DI Desktop database is fairly comprehensive in its geographic and temporal coverage of production data, completion date information can lag behind by a year or more afterwards and is not universally available for all areas of the country. Therefore, the list of wells with explicit well completion dates of 2011 was supplemented with those wells having a date (month) of 1st production of either gas or oil in 2011. This methodology is consistent with the methodology used to estimate well completions in the "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011 (April 12, 2013)".

Using this approach, 39,262 conventional and unconventional well completions were identified for 2011.

Once the population of wells completed in 2011 was identified, hydraulically fractured wells were identified as those wells meeting either of the following:

- Wells completed in a coalbed methane, tight, or shale formation as determined using the DOE EIA formation type crosswalk; or
- Wells identified in the DI Desktop database as horizontal wells.

The DOE EIA formation type crosswalk used in this analysis may be found in Attachment A. This methodology is consistent with the methodology used to identify the number of hydraulically fractured well completions in the "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011 (April 12, 2013)".

Using this approach, 15,979 hydraulically fractured (or unconventional) well completions were identified for 2011.

Oil Wells Hydraulically Fractured in 2011

Once the population of hydraulically fractured wells completed in 2011 was identified, each well was then classified as either an oil well or a gas well. Gas wells were defined as those wells with an average gas to liquids ratio greater than or equal to 12,500 standard cubic feet per barrel over the lifetime of the well, and oil wells were defined as those wells with an average gas to liquids ratio less than 12,500 standard cubic feet per barrel over the lifetime of the well. Note that the "liquids" quantity used in this analysis does not include produced water. This methodology is consistent with the gas-oil ratio methodology used in the 2012 Oil and Natural Gas Sector NSPS development.

Using this approach, 6,169 hydraulically fractured (or unconventional) oil well completions were identified for 2011.

Daily Gas Production of Oil Wells Hydraulically Fractured in 2011

Once the population of hydraulically fractured oil wells completed in 2011 was identified, the average daily gas production for each well was calculated based on the cumulative gas production from each well during its first year of production. This information was then averaged at the county-level, as well as at the national level. Nationally, the average daily gas production at an oil well that was hydraulically fractured in 2011 was 152 MCF.

Summary Information

Table 1 below presents a state-level summary of the derived information on hydraulically fractured oil wells completed in 2011. Attachment B contains the same information at the county and national level.

Table 1. Summary of Gas Production at Hydraulically Fractured (or unconventional) Oil Wells

State	Number of Counties	Number of Unconventional Oil Well Completions	Average Associated Gas Production over the 1st year (MCF/Day) [a]
AR	2	19	110.03
CO	12	1057	95.46
FL	1	1	5.81
KS	3	5	0.80
LA	17	24	111.87
MI	4	7	5.58
MS	1	1	0
MT	13	95	31.21
ND	14	1299	138.14
NM	6	337	114.89
NY	1	19	0
OH	32	214	4.43
OK	14	89	143.62
PA	5	7	78.38
SD	1	2	42.79
TX	88	2855	284.09
WV	5	11	173.15
WY	14	127	48.62

[a] Determined by taking the total production from the first 12 months of production and dividing by 365 days.

Observations

The analysis conducted under this task was performed in accordance with the procedures described above. With respect to qualitative observations made while implementing these procedures, ERG notes the following:

- In some instances, the date (month) of 1st production only included oil production, with no corresponding gas production recorded for that month;
- In some instances, there were months within the 1st year of production where there was no production (of oil, gas, or both) recorded for the well;
- For 415 oil wells hydraulically fractured and completed in 2011, there was no gas production reported for the well during the 1st year of production.

The net effect of these situations is that the average daily gas production values may be skewed low, for example, due to a well being shut in for some period of time after initially being brought into production.

In the case of the 415 wells where there was no gas production reported for the well during the 1st year of production, summary data is presented in Attachment B excluding these records. This data is reflected in the summary sheets indicating “WITHOUT ZERO”. The effect of this differentiation is easily seen in the “UNCONV_OIL_NATIONWIDE” sheet, which shows an average daily gas production of 152 (MCF/day) for all records, and an average daily gas production of 189 (MCF/day) when including only those records with some gas production.

Attachment A: DOE EIA Formation Type Crosswalk

(Formation Crosswalk-Memo Counts 2012 08 28_From ECR.xlsx)

Attachment B: National and County-level Summary of Average Daily Gas Production from Hydraulically Fractured Oil Well Completions in 2011

(Task 2 Summary.xlsx)

UNCONVENTIONAL OIL COUNTY WITH ZERO

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
05027	AR	Columbia	17	220.06
05139	AR	Union	2	-
08001	CO	Adams	8	75.81
08005	CO	Arapahoe	1	100.28
08013	CO	Boulder	4	173.39
08014	CO	Broomfield	12	194.15
08043	CO	Fremont	4	15.34
08057	CO	Jackson	1	281.19
08069	CO	Larimer	14	24.35
08077	CO	Mesa	1	0.43
08081	CO	Moffat	2	73.42
08087	CO	Morgan	1	14.65
08103	CO	Rio Blanco	3	62.57
08123	CO	Weld	1006	129.94
12087	FL	Monroe	1	5.81
20073	KS	Greenwood	1	-
20097	KS	Kiowa	1	-
20125	KS	Montgomery	3	2.40
22009	LA	Avoyelles	2	1.12

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
22011	LA	Beauregard	1	141.90
22015	LA	Bossier	1	-
22017	LA	Caddo	2	5.65
22019	LA	Calcasieu	1	-
22023	LA	Cameron	1	77.58
22027	LA	Claiborne	3	1.56
22037	LA	East Feliciana	1	23.45
22047	LA	Iberville	1	68.21
22075	LA	Plaquemines	1	44.28
22079	LA	Rapides	1	6.08
22091	LA	St. Helena	1	77.15
22097	LA	St. Landry	3	44.34
22101	LA	St. Mary	1	10.77
22111	LA	Union	1	5.58
22119	LA	Webster	1	1,382.30
22127	LA	Winn	2	11.78
26075	MI	Jackson	3	22.32
26091	MI	Lenawee	2	-
26141	MI	Presque Isle	1	-
26147	MI	St. Clair	1	-
28063	MS	Jefferson	1	-
30005	MT	Blaine	4	-

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
30009	MT	Carbon	2	9.60
30021	MT	Dawson	1	29.33
30025	MT	Fallon	1	138.62
30035	MT	Glacier	9	29.37
30065	MT	Musselshell	1	-
30069	MT	Petroleum	4	-
30073	MT	Pondera	1	-
30083	MT	Richland	32	94.43
30085	MT	Roosevelt	27	102.11
30087	MT	Rosebud	2	-
30091	MT	Sheridan	10	2.30
30099	MT	Teton	1	-
35005	NM	Chaves	6	90.22
35015	NM	Eddy	206	317.14
35025	NM	Lea	121	160.97
35039	NM	Rio Arriba	2	57.02
35043	NM	Sandoval	1	-
35045	NM	San Juan	1	64.03
36009	NY	Cattaraugus	19	-
38007	ND	Billings	22	157.36
38009	ND	Bottineau	10	2.69
38011	ND	Bowman	4	84.54

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
38013	ND	Burke	42	83.17
38023	ND	Divide	74	144.13
38025	ND	Dunn	208	156.73
38033	ND	Golden Valley	3	131.73
38053	ND	McKenzie	297	355.17
38055	ND	McLean	11	102.95
38061	ND	Mountrail	329	176.74
38075	ND	Renville	2	-
38087	ND	Slope	1	140.16
38089	ND	Stark	28	184.08
38105	ND	Williams	268	214.53
39005	OH	Ashland	23	-
39007	OH	Ashtabula	1	20.94
39009	OH	Athens	3	2.47
39019	OH	Carroll	6	4.31
39029	OH	Columbiana	1	6.35
39031	OH	Coshocton	8	0.75
39035	OH	Cuyahoga	7	12.35
39055	OH	Geauga	7	4.13
39067	OH	Harrison	3	1.57
39073	OH	Hocking	2	-
39075	OH	Holmes	14	0.23

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
39081	OH	Jefferson	6	-
39083	OH	Knox	13	1.67
39089	OH	Licking	17	-
39093	OH	Lorain	1	-
39099	OH	Mahoning	3	4.72
39101	OH	Marion	1	-
39103	OH	Medina	12	0.72
39105	OH	Meigs	1	2.08
39111	OH	Monroe	13	1.05
39115	OH	Morgan	6	0.16
39119	OH	Muskingum	9	0.79
39121	OH	Noble	1	-
39127	OH	Perry	2	0.40
39133	OH	Portage	10	10.29
39151	OH	Stark	22	6.70
39153	OH	Summit	8	25.92
39155	OH	Trumbull	4	19.92
39157	OH	Tuscarawas	2	2.52
39167	OH	Washington	6	0.35
39169	OH	Wayne	1	0.47
39175	OH	Wyandot	1	10.79
40011	OK	Blaine	4	138.44

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
40015	OK	Caddo	2	-
40017	OK	Canadian	24	59.77
40029	OK	Coal	14	-
40039	OK	Custer	4	73.81
40043	OK	Dewey	5	25.28
40045	OK	Ellis	13	82.28
40051	OK	Grady	4	-
40069	OK	Johnston	1	273.04
40095	OK	Marshall	1	758.99
40125	OK	Pottawatomi e	1	-
40129	OK	Roger Mills	4	60.26
40149	OK	Washita	11	25.78
40151	OK	Woods	1	513.08
42019	PA	Butler	1	3.00
42083	PA	McKean	1	2.85
42123	PA	Warren	1	1.17
42125	PA	Washington	2	322.21
42129	PA	Westmorela nd	2	62.65
46063	SD	Harding	2	42.79
48003	TX	Andrews	18	27.20
48009	TX	Archer	4	7.96
48013	TX	Atascosa	70	119.71

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48033	TX	Borden	1	-
48041	TX	Brazos	17	88.27
48051	TX	Burleson	15	25.89
48055	TX	Caldwell	29	-
48077	TX	Clay	3	75.75
48079	TX	Cochran	3	0.73
48097	TX	Cooke	99	297.95
48103	TX	Crane	19	110.50
48105	TX	Crockett	20	151.12
48109	TX	Culberson	1	2,500.75
48123	TX	DeWitt	145	1,332.05
48127	TX	Dimmit	322	379.76
48135	TX	Ector	15	12.91
48149	TX	Fayette	13	79.71
48151	TX	Fisher	2	1.68
48163	TX	Frio	72	105.01
48165	TX	Gaines	1	3.92
48169	TX	Garza	1	-
48173	TX	Glasscock	19	272.15
48177	TX	Gonzales	207	98.80
48181	TX	Grayson	4	367.12
48183	TX	Gregg	3	23.02

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48185	TX	Grimes	7	586.87
48187	TX	Guadalupe	2	-
48195	TX	Hansford	3	93.42
48197	TX	Hardeman	2	74.00
48201	TX	Harris	1	1.84
48203	TX	Harrison	2	13.53
48211	TX	Hemphill	15	390.47
48225	TX	Houston	1	127.46
48235	TX	Irion	87	112.45
48237	TX	Jack	22	122.06
48241	TX	Jasper	2	1,387.63
48255	TX	Karnes	309	388.35
48263	TX	Kent	1	-
48273	TX	Kleberg	2	33.10
48283	TX	La Salle	216	185.29
48285	TX	Lavaca	13	83.04
48287	TX	Lee	5	25.93
48289	TX	Leon	19	61.86
48295	TX	Lipscomb	84	403.67
48297	TX	Live Oak	89	731.54
48301	TX	Loving	28	276.40
48311	TX	McMullen	130	276.52

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48313	TX	Madison	21	173.35
48317	TX	Martin	1	50.01
48323	TX	Maverick	23	110.15
48329	TX	Midland	1	12.33
48331	TX	Milam	3	34.19
48337	TX	Montague	119	362.22
48351	TX	Newton	2	2,539.85
48353	TX	Nolan	24	20.97
48355	TX	Nueces	3	1,746.66
48357	TX	Ochiltree	82	261.41
48363	TX	Palo Pinto	3	244.63
48365	TX	Panola	2	220.47
48367	TX	Parker	1	20.61
48371	TX	Pecos	8	42.56
48373	TX	Polk	4	1,394.01
48383	TX	Reagan	15	66.05
48389	TX	Reeves	39	184.15
48393	TX	Roberts	21	445.09
48395	TX	Robertson	15	22.76
48401	TX	Rusk	3	5.40
48405	TX	San Augustine	1	1,052.92
48413	TX	Schleicher	1	171.38

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
48415	TX	Scurry	5	84.33
48417	TX	Shackelford	1	-
48425	TX	Somervell	2	1.29
48429	TX	Stephens	2	27.98
48433	TX	Stonewall	18	0.61
48439	TX	Tarrant	1	60.16
48449	TX	Titus	1	-
48457	TX	Tyler	2	1,099.59
48459	TX	Upshur	1	49.13
48461	TX	Upton	12	3.26
48475	TX	Ward	73	375.79
48477	TX	Washington	1	276.18
48479	TX	Webb	44	874.17
48483	TX	Wheeler	60	965.66
48493	TX	Wilson	33	36.46
48495	TX	Winkler	7	137.90
48497	TX	Wise	3	342.57
48503	TX	Young	2	-
48507	TX	Zavala	52	26.70
54001	WV	Barbour	1	1.05
54051	WV	Marshall	1	782.02
54053	WV	Mason	1	1.40

FIPS_ CODE	STATE_ ABBR	COUNTY_NA ME	NUMBER_UNCONVENTIONAL_OIL_ WELL_COMPLETIONS	AVG_ASSOCIATED_GAS _MCF_PER_DAY
54085	WV	Ritchie	1	-
54103	WV	Wetzel	7	81.30
56003	WY	Big Horn	1	10.12
56005	WY	Campbell	29	282.44
56007	WY	Carbon	2	3.52
56009	WY	Converse	45	190.09
56013	WY	Fremont	3	2.17
56015	WY	Goshen	4	11.56
56017	WY	Hot Springs	1	0.11
56019	WY	Johnson	2	29.93
56021	WY	Laramie	22	56.63
56025	WY	Natrona	2	0.02
56027	WY	Niobrara	2	20.77
56029	WY	Park	3	5.60
56031	WY	Platte	2	8.15
56037	WY	Sweetwater	9	59.59

UNCONVENTONAL OIL COUTTY WITHOUT ZERO

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
05027	AR	Columbia	17	220.06
08001	CO	Adams	8	75.81
08005	CO	Arapahoe	1	100.28
08013	CO	Boulder	4	173.39
08014	CO	Broomfield	12	194.15
08043	CO	Fremont	4	15.34
08057	CO	Jackson	1	281.19
08069	CO	Larimer	14	24.35
08077	CO	Mesa	1	0.43
08081	CO	Moffat	2	73.42
08087	CO	Morgan	1	14.65
08103	CO	Rio Blanco	1	187.70
08123	CO	Weld	1000	130.72
12087	FL	Monroe	1	5.81
20125	KS	Montgomery	3	2.40
22009	LA	Avoyelles	1	2.24
22011	LA	Beauregard	1	141.90
22017	LA	Caddo	1	11.31
22023	LA	Cameron	1	77.58
22027	LA	Claiborne	1	4.67
22037	LA	East Feliciana	1	23.45
22047	LA	Iberville	1	68.21

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
22075	LA	Plaquemines	1	44.28
22079	LA	Rapides	1	6.08
22091	LA	St. Helena	1	77.15
22097	LA	St. Landry	2	66.51
22101	LA	St. Mary	1	10.77
22111	LA	Union	1	5.58
22119	LA	Webster	1	1,382.30
22127	LA	Winn	2	11.78
26075	MI	Jackson	2	33.48
30009	MT	Carbon	1	19.19
30021	MT	Dawson	1	29.33
30025	MT	Fallon	1	138.62
30035	MT	Glacier	7	37.76
30083	MT	Richland	30	100.73
30085	MT	Roosevelt	27	102.11
30091	MT	Sheridan	7	3.28
35005	NM	Chaves	5	108.26
35015	NM	Eddy	205	318.68
35025	NM	Lea	112	173.90
35039	NM	Rio Arriba	2	57.02
35045	NM	San Juan	1	64.03
38007	ND	Billings	22	157.36

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
38009	ND	Bottineau	5	5.38
38011	ND	Bowman	4	84.54
38013	ND	Burke	42	83.17
38023	ND	Divide	74	144.13
38025	ND	Dunn	208	156.73
38033	ND	Golden Valley	3	131.73
38053	ND	McKenzie	295	357.58
38055	ND	McLean	11	102.95
38061	ND	Mountrail	329	176.74
38087	ND	Slope	1	140.16
38089	ND	Stark	28	184.08
38105	ND	Williams	268	214.53
39007	OH	Ashtabula	1	20.94
39009	OH	Athens	2	3.70
39019	OH	Carroll	4	6.46
39029	OH	Columbiana	1	6.35
39031	OH	Coshocton	3	2.00
39035	OH	Cuyahoga	7	12.35
39055	OH	Geauga	7	4.13
39067	OH	Harrison	2	2.36
39075	OH	Holmes	4	0.82
39083	OH	Knox	8	2.71

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
39099	OH	Mahoning	2	7.08
39103	OH	Medina	2	4.31
39105	OH	Meigs	1	2.08
39111	OH	Monroe	8	1.71
39115	OH	Morgan	3	0.32
39119	OH	Muskingum	4	1.78
39127	OH	Perry	1	0.79
39133	OH	Portage	9	11.43
39151	OH	Stark	17	8.67
39153	OH	Summit	7	29.62
39155	OH	Trumbull	4	19.92
39157	OH	Tuscarawas	1	5.04
39167	OH	Washington	2	1.04
39169	OH	Wayne	1	0.47
39175	OH	Wyandot	1	10.79
40011	OK	Blaine	4	138.44
40017	OK	Canadian	8	179.30
40039	OK	Custer	2	147.61
40043	OK	Dewey	2	63.20
40045	OK	Ellis	9	118.85
40069	OK	Johnston	1	273.04
40095	OK	Marshall	1	758.99

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
40129	OK	Roger Mills	3	80.35
40149	OK	Washita	1	283.55
40151	OK	Woods	1	513.08
42019	PA	Butler	1	3.00
42083	PA	McKean	1	2.85
42123	PA	Warren	1	1.17
42125	PA	Washington	2	322.21
42129	PA	Westmoreland	2	62.65
46063	SD	Harding	1	85.59
48003	TX	Andrews	16	30.60
48009	TX	Archer	1	31.86
48013	TX	Atascosa	69	121.44
48041	TX	Brazos	17	88.27
48051	TX	Burleson	6	64.72
48077	TX	Clay	3	75.75
48079	TX	Cochran	3	0.73
48097	TX	Cooke	99	297.95
48103	TX	Crane	19	110.50
48105	TX	Crockett	19	159.07
48109	TX	Culberson	1	2,500.75
48123	TX	DeWitt	143	1,350.68
48127	TX	Dimmit	317	385.75

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48135	TX	Ector	15	12.91
48149	TX	Fayette	12	86.35
48151	TX	Fisher	2	1.68
48163	TX	Frio	58	130.36
48165	TX	Gaines	1	3.92
48173	TX	Glasscock	19	272.15
48177	TX	Gonzales	196	104.35
48181	TX	Grayson	3	489.50
48183	TX	Gregg	3	23.02
48185	TX	Grimes	7	586.87
48195	TX	Hansford	3	93.42
48197	TX	Hardeman	1	147.99
48201	TX	Harris	1	1.84
48203	TX	Harrison	1	27.06
48211	TX	Hemphill	15	390.47
48225	TX	Houston	1	127.46
48235	TX	Irion	87	112.45
48237	TX	Jack	22	122.06
48241	TX	Jasper	2	1,387.63
48255	TX	Karnes	303	396.04
48273	TX	Kleberg	2	33.10
48283	TX	La Salle	214	187.02

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48285	TX	Lavaca	13	83.04
48287	TX	Lee	3	43.21
48289	TX	Leon	16	73.46
48295	TX	Lipscomb	82	413.52
48297	TX	Live Oak	89	731.54
48301	TX	Loving	26	297.66
48311	TX	McMullen	125	287.58
48313	TX	Madison	20	182.01
48317	TX	Martin	1	50.01
48323	TX	Maverick	18	140.75
48329	TX	Midland	1	12.33
48331	TX	Milam	2	51.29
48337	TX	Montague	115	374.82
48351	TX	Newton	2	2,539.85
48353	TX	Nolan	22	22.87
48355	TX	Nueces	3	1,746.66
48357	TX	Ochiltree	82	261.41
48363	TX	Palo Pinto	3	244.63
48365	TX	Panola	2	220.47
48367	TX	Parker	1	20.61
48371	TX	Pecos	8	42.56
48373	TX	Polk	4	1,394.01

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48383	TX	Reagan	14	70.77
48389	TX	Reeves	37	194.11
48393	TX	Roberts	21	445.09
48395	TX	Robertson	12	28.45
48401	TX	Rusk	1	16.21
48405	TX	San Augustine	1	1,052.92
48413	TX	Schleicher	1	171.38
48415	TX	Scurry	5	84.33
48425	TX	Somervell	2	1.29
48429	TX	Stephens	2	27.98
48433	TX	Stonewall	15	0.74
48439	TX	Tarrant	1	60.16
48457	TX	Tyler	2	1,099.59
48459	TX	Upshur	1	49.13
48461	TX	Upton	12	3.26
48475	TX	Ward	73	375.79
48477	TX	Washington	1	276.18
48479	TX	Webb	44	874.17
48483	TX	Wheeler	59	982.03
48493	TX	Wilson	28	42.98
48495	TX	Winkler	7	137.90
48497	TX	Wise	3	342.57

FIPS_CODE	STATE_ABBR	COUNTY_NAME	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
48507	TX	Zavala	45	30.86
54001	WV	Barbour	1	1.05
54051	WV	Marshall	1	782.02
54053	WV	Mason	1	1.40
54103	WV	Wetzel	7	81.30
56003	WY	Big Horn	1	10.12
56005	WY	Campbell	27	303.36
56007	WY	Carbon	1	7.03
56009	WY	Converse	45	190.09
56013	WY	Fremont	1	6.52
56015	WY	Goshen	4	11.56
56017	WY	Hot Springs	1	0.11
56019	WY	Johnson	2	29.93
56021	WY	Laramie	21	59.33
56025	WY	Natrona	1	0.03
56027	WY	Niobrara	1	41.54
56029	WY	Park	3	5.60
56031	WY	Platte	2	8.15
56037	WY	Sweetwater	8	67.04

UNCONVENTIONAL OIL NATIONWIDE

NATIONWIDE UNCONVENTIONAL OIL WELL COMPLETIONS (WITH ZERO)

GEOGRAPHIC	NUMBER_OF_STATES	NUMBER_OF_COUNTIES	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
NATIONWIDE	18	233	6169	152.19

NATIONWIDE UNCONVENTIONAL OIL WELL COMPLETIONS (WITHOUT ZERO)

GEOGRAPHIC	NUMBER_OF_STATES	NUMBER_OF_COUNTIES	NUMBER_UNCONVENTIONAL_OIL_WELL_COMPLETIONS	AVG_ASSOCIATED_GAS_MCF_PER_DAY
NATIONWIDE	16	195	5754	189.35

Chapter 7

FLARES

Diana K. Stone
Susan K. Lynch
Richard F. Pandullo
Radian Corporation
Research Triangle Park, NC 27709

Leslie B. Evans, Organic Chemicals Group
William M. Vatavuk, Innovative Strategies and Economics Group
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

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7.1 Introduction

Flaring is a volatile organic compound (VOC) combustion control process in which the VOCs are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete (> 98%) VOC destruction. Completeness of combustion in a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all VOCs are converted to carbon dioxide and water. Incomplete combustion results in some of the VOC being unaltered or converted to other organic compounds such as aldehydes or acids.

The flaring process can produce some undesirable by-products including noise, smoke, heat radiation, light, SO_x, NO_x, CO, and an additional source of ignition where not desired. However, by proper design these can be minimized.

7.1.1 Flare Types

Flares are generally categorized in two ways: (1) by the height of the flare tip (*i.e.*, ground or elevated), and (2) by the method of enhancing mixing at the flare tip (*i.e.*, steam-assisted, air-assisted, pressure-assisted, or non-assisted). Elevating the flare can prevent potentially dangerous conditions at ground level where the open flame (*i.e.*, an ignition source) is located near a process unit. Further, the products of combustion can be dispersed above working areas to reduce the effects of noise, heat, smoke, and objectionable odors.

In most flares, combustion occurs by means of a diffusion flame. A diffusion flame is one in which air diffuses across the boundary of the fuel/combustion product stream toward the center of the fuel flow, forming the envelope of a combustible gas mixture around a core of fuel gas. This mixture, on ignition, establishes a stable flame zone around the gas core above the burner tip. This inner gas core is heated by diffusion of hot combustion products from the flame zone.

Cracking can occur with the formation of small hot particles of carbon that give the flame its characteristic luminosity. If there is an oxygen deficiency and if the carbon particles are cooled to below their ignition temperature, smoking occurs. In large diffusion flames, combustion product vortices can form around burning portions of the gas and shut off the supply of oxygen. This localized instability causes flame flickering, which can be accompanied by soot formation.

As in all combustion processes, an adequate air supply and good mixing are required to complete combustion and minimize smoke. The various flare designs differ primarily in their accomplishment of mixing.

7.1.1.1 Steam-Assisted Flares

Steam-assisted flares are single burner tips, elevated above ground level for safety reasons, that burn the vented gas in essentially a diffusion flame. They reportedly account for the majority of the flares installed and are the predominant flare type found in refineries and chemical plants.[1,2]

To ensure an adequate air supply and good mixing, this type of flare system injects steam into the combustion zone to promote turbulence for mixing and to induce air into the flame. Steam-assisted flares are the focus of the chapter and will be discussed in greater detail in Sections 7.2 through 7.4.

7.1.1.2 Air-Assisted Flares

Some flares use forced air to provide the combustion air and the mixing required for smokeless operation. These flares are built with a spider-shaped burner (with many small gas orifices) located inside but near the top of a steel cylinder two feet or more in diameter. Combustion air is provided by a fan in the bottom of the cylinder. The amount of combustion air can be varied by varying the fan speed. The principal advantage of the air-assisted flares is that they can be used where steam is not available. Although air assist is not usually used on large flares (because it is generally not economical when the gas volume is large[3]) the number of large air-assisted flares being built is increasing.[4]

7.1.1.3 Non-Assisted Flares

The non-assisted flare is just a flare tip without any auxiliary provision for enhancing the mixing of air into its flame. Its use is limited essentially to gas streams that have a low heat content and a low carbon/hydrogen ratio that burn readily without producing smoke.[5] These streams require less air for complete combustion, have lower combustion temperatures that minimize cracking reactions, and are more resistant to cracking.

7.1.1.4 Pressure-Assisted Flares

Pressure-assisted flares use the vent stream pressure to promote mixing at the burner tip. Several vendors now market proprietary, high pressure drop burner tip designs. If sufficient vent stream pressure is available, these flares can be applied to streams previously requiring steam or air assist for smokeless operation. Pressure-assisted flares generally (but not necessarily) have the burner arrangement at ground level, and consequently, must be located in a remote area of the plant where there is plenty of space available. They have multiple burner heads that are staged to operate based on the quantity of gas being released. The size, design, number, and group arrangement of the burner heads depend on the vent gas characteristics.

7.1.1.5 Enclosed Ground Flares

An enclosed flare's burner heads are inside a shell that is internally insulated. This shell reduces noise, luminosity, and heat radiation and provides wind protection. A high nozzle pressure drop is usually adequate to provide the mixing necessary for smokeless operation and air or steam assist is not required. In this context, enclosed flares can be considered a special class of pressure-assisted or non-assisted flares. The height must be adequate for creating enough draft to supply sufficient air for smokeless combustion and for dispersion of the thermal plume. These flares are always at ground level.

Enclosed flares generally have less capacity than open flares and are used to combust continuous, constant flow vent streams, although reliable and efficient operation can be attained over a wide range of design capacity. Stable combustion can be obtained with lower Btu content vent gases than is possible with open flare designs (50 to 60 Btu/scf has been reported)[2], probably due to their isolation from wind effects. Enclosed flares are typically found at landfills.

7.1.2 Applicability

Flares can be used to control almost any VOC stream, and can handle fluctuations in VOC concentration, flow rate, heating value, and inerts content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications. The majority of chemical plants and refineries have existing flare systems designed to relieve emergency process upsets that require release of large volumes of gas. These large diameter flares designed to handle emergency releases, can also be used to control vent streams from various process operations. Consideration of vent stream flow rate and available pressure must be given for retrofit applications. Normally, emergency relief flare systems are operated at a small percentage of capacity and at negligible pressure. To consider the effect of controlling an additional vent stream, the maximum gas velocity, system pressure, and ground level heat radiation during an emergency release must be evaluated. Further, if the vent stream pressure is not sufficient to overcome the flare system pressure, then the economics of a gas mover system must be evaluated, If adding the vent stream causes the maximum velocity limits or ground level heat radiation limits to be exceeded, then a retrofit application is not viable.

Many flare systems are currently operated in conjunction with baseload gas recovery systems. These systems recover and compress the waste VOC for use as a feedstock in other processes or as fuel. When baseload gas recovery systems are applied, the flare is used in a backup capacity and for emergency releases. Depending on the quantity of usable VOC that can be recovered, there can be a considerable economic advantage over operation of a flare alone.

Streams containing high concentrations of halogenated or sulfur containing compounds are not usually flared due to corrosion of the flare tip or formation of secondary pollutants (such as SO_2). If these vent types are to be controlled by combustion, thermal incineration, followed by scrubbing to remove the acid gases, is the preferred method.[3]

7.1.3 Performance

This section discusses the parameters that affect flare VOC destruction efficiency and presents the specifications that must be followed when flares are used to comply with EPA air emission standards.

7.1.3.1 Factors Affecting Efficiency

The major factors affecting flare combustion efficiency are vent gas flammability, auto-ignition temperature, heating value (Btu/scf), density, and flame zone mixing.

The flammability limits of the flared gases influence ignition stability and flame extinction. The flammability limits are defined as the stoichiometric composition limits (maximum and minimum) of an oxygen-fuel mixture that will burn indefinitely at given conditions of temperature and pressure without further ignition. In other words, gases must be within their flammability limits to burn. When flammability limits are narrow, the interior of the flame may have insufficient air for the mixture to burn. Fuels, such as hydrogen, with wide limits of flammability are therefore easier to combust.

For most vent streams, the heating value also affects flame stability, emissions, and flame structure. A lower heating value produces a cooler flame that does not favor combustion kinetics and is also more easily extinguished. The lower flame temperature also reduces buoyant forces, which reduces mixing.

The density of the vent stream also affects the structure and stability of the flame through the effect on buoyancy and mixing. By design, the velocity in many flares is very low; therefore, most of the flame structure is developed through buoyant forces as a result of combustion. Lighter gases therefore tend to burn better. In addition to burner tip design, the density also directly affects the minimum purge gas required to prevent flashback, with lighter gases requiring more purge.[5]

Poor mixing at the flare tip is the primary cause of flare smoking when burning a given material. Streams with high carbon-to-hydrogen mole ratio (greater than 0.35) have a greater tendency to smoke and require better mixing for smokeless flaring.[3] For this reason one generic steam-to-vent gas ratio is not necessarily appropriate for all vent streams. The required steam rate is dependent on the carbon to hydrogen ratio of the gas being flared. A high ratio requires more steam to prevent a smoking flare.

7.1.3.2 Flare Specifications

At too high an exit velocity, the flame can lift off the tip and flame out, while at too low a velocity, it can burn back into the tip or down the sides of the stack.

The EPA requirements for flares used to comply with EPA air emission standards are specified in 40 CFR Section 60.18. The requirements are for steam-assisted, air-assisted, and non-assisted flares. Requirements for steam-assisted, elevated flares state that the flare shall be designed for and operated with:

- an exit velocity at the flare tip of less than 60 ft/sec for 300 Btu/scf gas streams and less than 400 ft/sec for >1,000 Btu/scf gas streams. For gas streams between 300-1,000 Btu/scf the maximum permitted velocity (V_{max}, in ft/sec) is determined by the following equation:

$$\log_{10}(V_{max}) = \frac{B_v + 1214}{852} \tag{7.1}$$

  where B_v is the net heating value in Btu/scf.

- no visible emissions. A five-minute exception period is allowed during any two consecutive hours.

- a flame present at all times when emissions may be vented. The presence of a pilot flame shall be monitored using a thermocouple or equivalent device.

- the net heating value of the gas being combusted being 300 Btu/scf or greater.

In addition, owners or operators must monitor to ensure that flares are operated and maintained in conformance with their design.

7.2 Process Description

The elements of an elevated steam-assisted flare generally consist of gas vent collection piping, utilities (fuel, steam, and air), piping from the base up, knock-out drum, liquid seal, flare stack, gas seal, burner tip, pilot burners, steam jets, ignition system, and controls. Figure 7.1

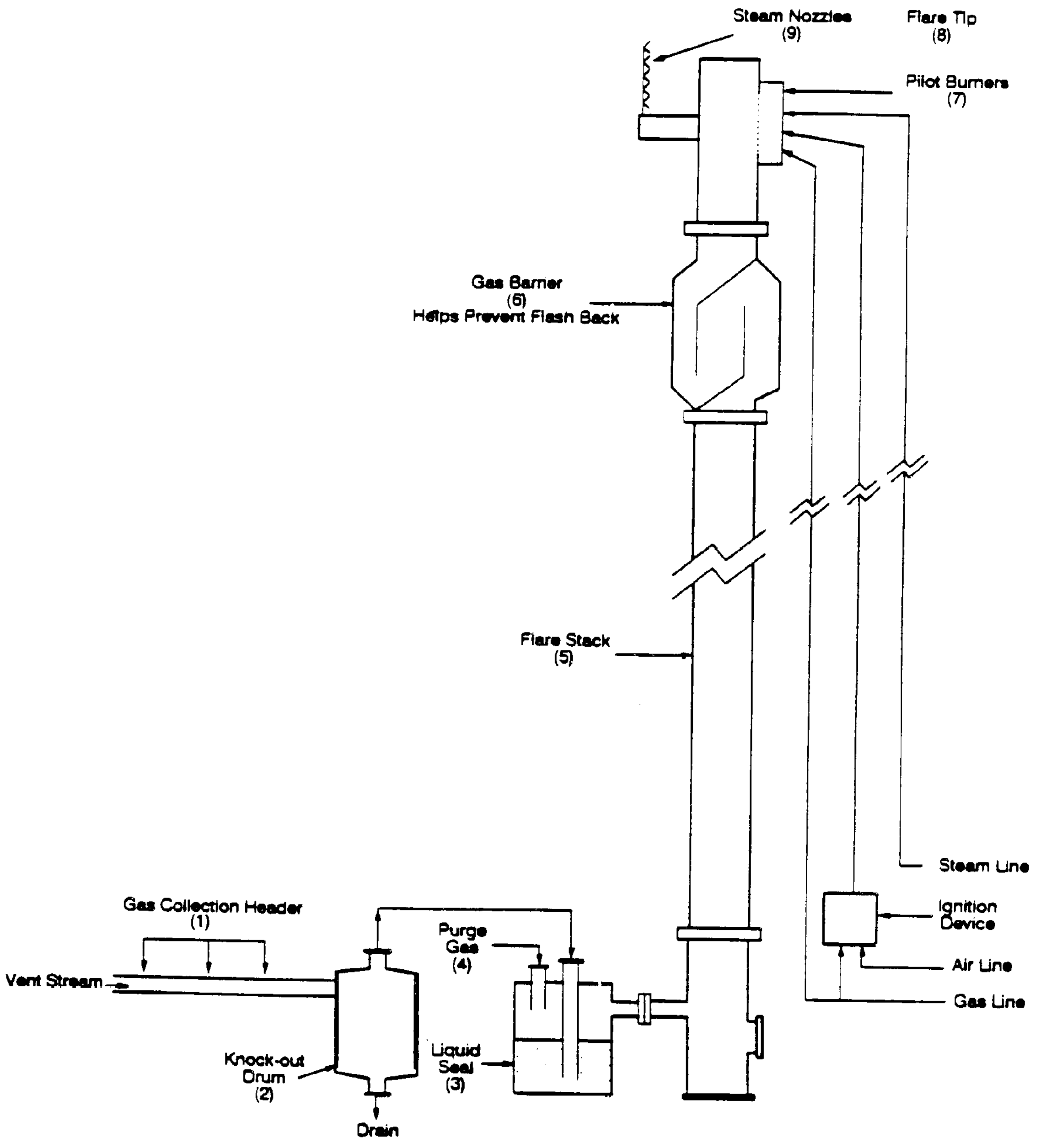

Figure 7.1: Steam-Assisted Elevated Flare System

is a diagram of a steam-assisted elevated smokeless flare system showing the usual components that are included.

7.2.1 Gas Transport Piping

Process vent streams are sent from the facility release point to the flare location through the gas collection header. The piping (generally schedule 40 carbon steel) is designed to minimize pressure drop. Ducting is not used as it is more prone to air leaks. Valving should be kept to an absolute minimum and should be "car-sealed" (sealed) open. Pipe layout is designed to avoid any potential dead legs and liquid traps. The piping is equipped for purging so that explosive mixtures do not occur in the flare system either on start-up or during operation.

7.2.2 Knock-out Drum

Liquids that may be in the vent stream gas or that may condense out in the collection header and transfer lines are removed by a knock-out drum. (See Figure 7.2.) The knock-out or disentrainment drum is typically either a horizontal or vertical vessel located at or close to the base of the flare, or a vertical vessel located inside the base of the flare stack. Liquid in the vent stream can extinguish the flame or cause irregular combustion and smoking. In addition, flaring liquids can generate a spray of burning chemicals that could reach ground level and create a safety hazard. For a flare system designed to handle emergency process upsets this drum must be sized for worst-case conditions (*e.g.*, loss of cooling water or total unit depressuring) and is usually quite large. For a flare system devoted only to vent stream VOC control, the sizing of the drum is based primarily on vent gas flow rate with consideration given to liquid entrainment.

7.2.3 Liquid Seal

Process vent streams are usually passed through a liquid seal before going to the flare stack. The liquid seal can be downstream of the knockout drum or incorporated into the same vessel. This prevents possible flame flashbacks, caused when air is inadvertently introduced into the flare system and the flame front pulls down into the stack. The liquid seal also serves to maintain a positive pressure on the upstream system and acts as a mechanical damper on any explosive shock wave in the flare stack.(51 Other devices, such as flame arresters and check valves, may sometimes replace a liquid seal or be used in conjunction with it. Purge gas (as discussed in Section 7.3.4) also helps to prevent flashback in the flare stack caused by low vent gas flow.

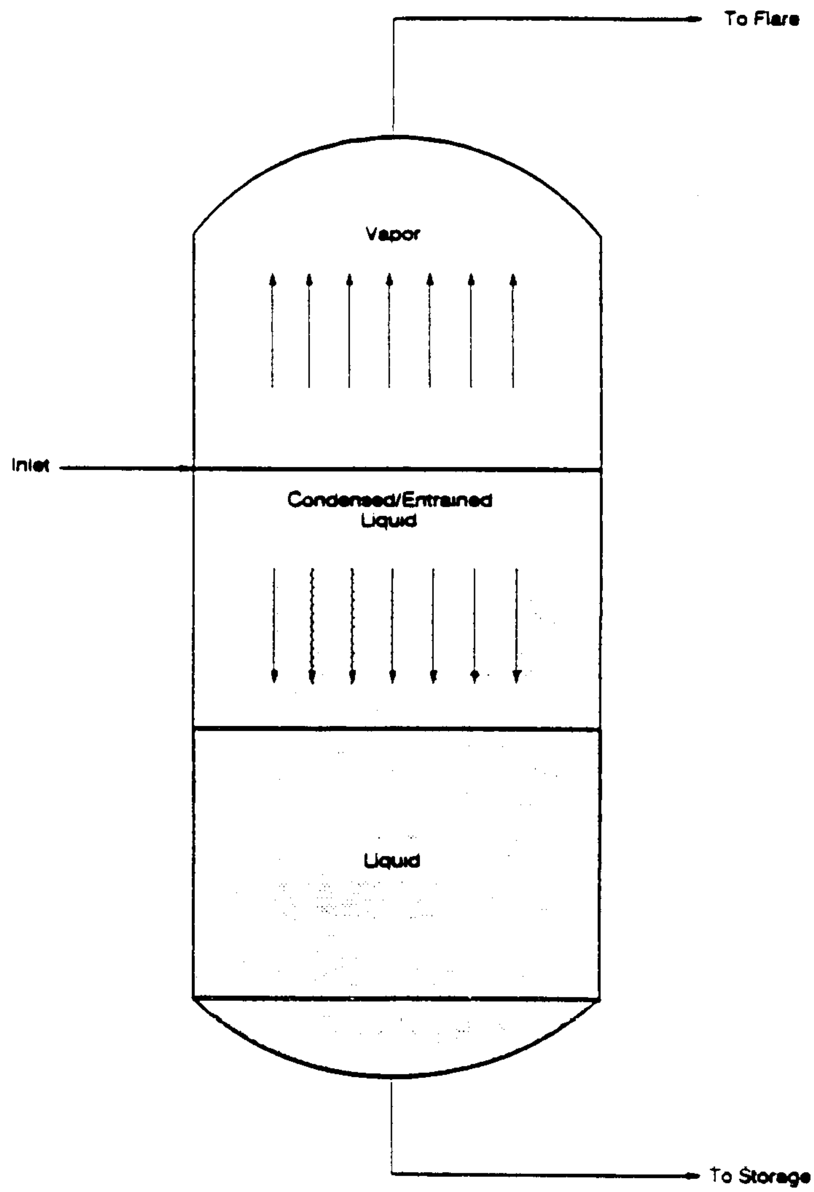

Figure 7.2: Typical Vertical Knock-out Drum

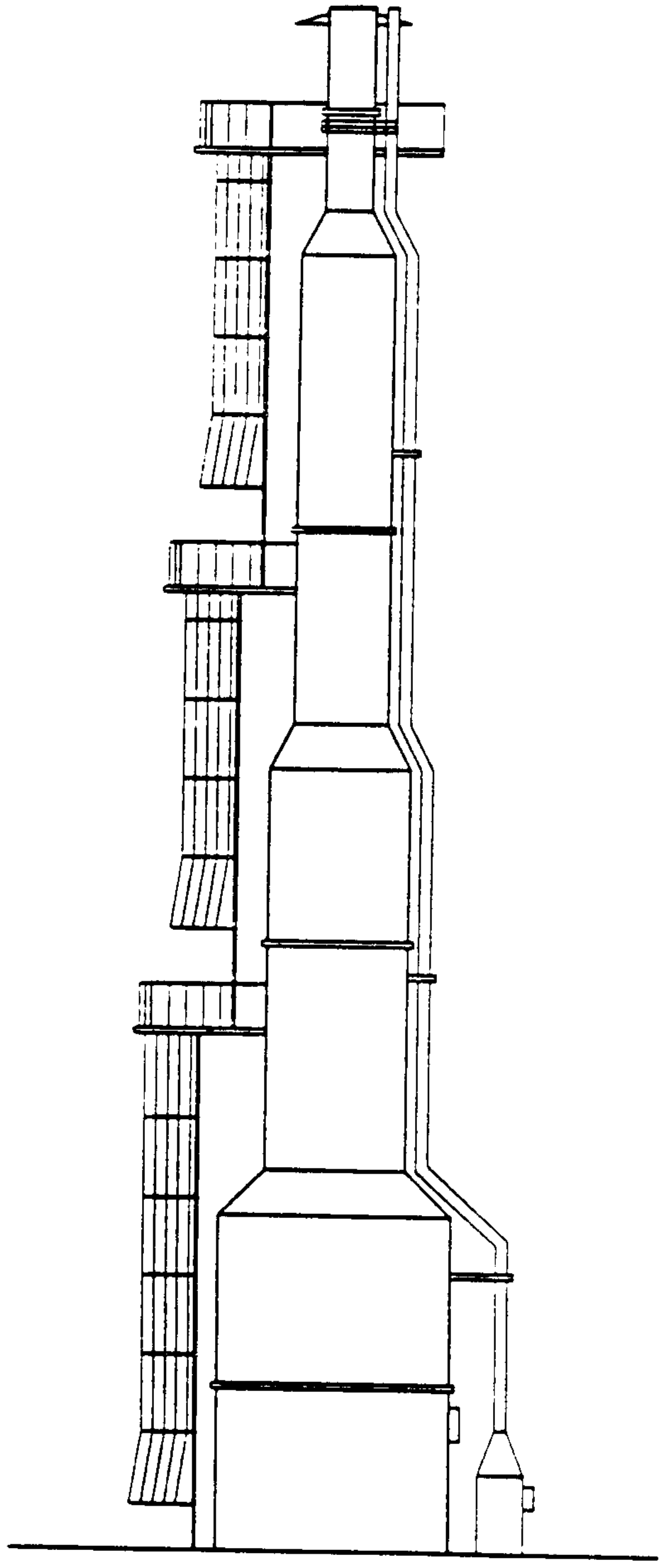

Figure 7.3: Self-Supported Elevated Flare

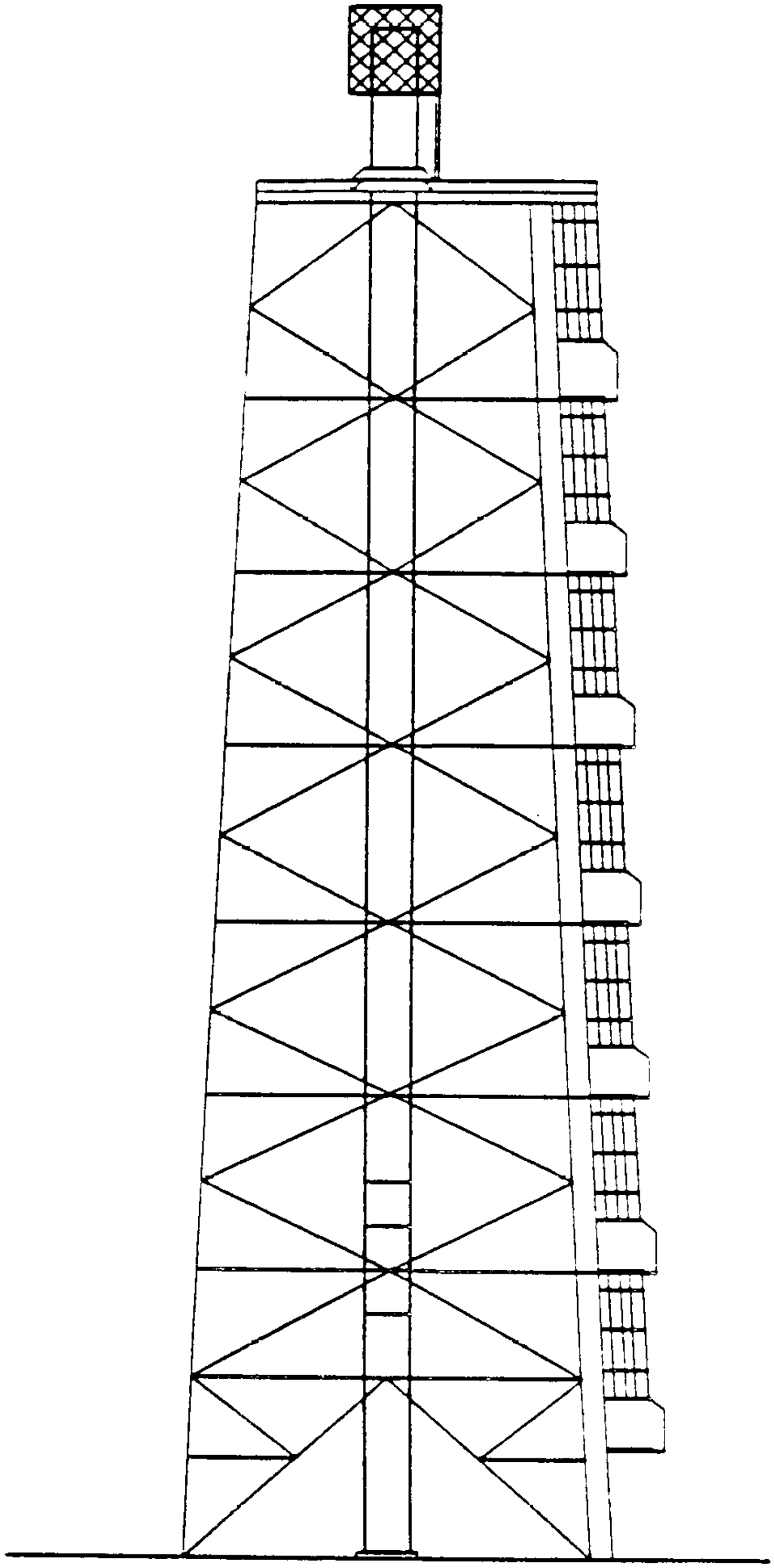

Figure 7.4: Derrick-Supported Elevated Flare

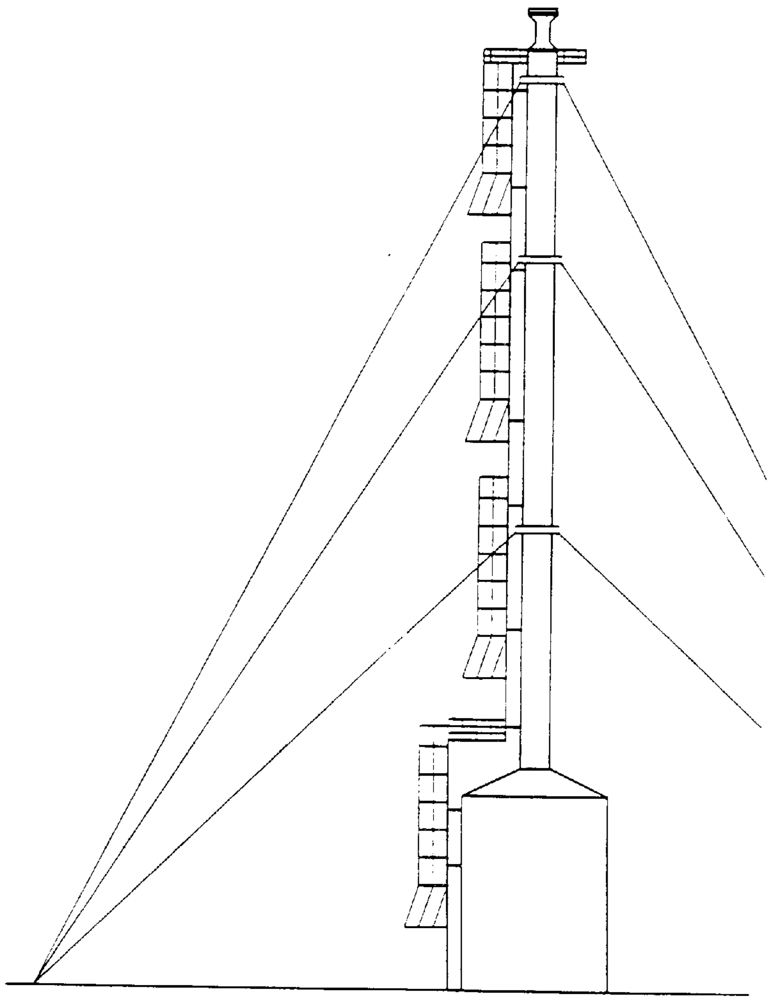

Figure 7.5: Guy-Supported Elevated Flare

7.2.4 Flare Stack

For safety reasons a stack is used to elevate the flare. The flare must he located so that it does not present a hazard to surrounding personnel and facilities. Elevated flares can be self-supported (free-standing), guyed, or structurally supported by a derrick. Examples of these three types of elevated flares are shown in Figures 7.3, 7.4, and 7.5 for self-supported, derrick - supported, and guy-supported flares, respectively. Self-supporting flares are generally used for lower flare tower heights (30-100 feet) but can be designed for up to 250 feet. Guy towers are designed for over 300 feet, while derrick towers are designed for above 200 feet.[4, 6, 7, 8, 9, 10]

Free-standing flares provide ideal structural support. However, for very high units the costs increase rapidly. In addition, the foundation required and nature of the soil must be considered.

Derrick-supported flares can be built as high as required since the system load is spread over the derrick structure. This design provides for differential expansion between the stack, piping, and derrick. Derrick-supported flares are the most expensive design for a given flare height.

The guy-supported flare is the simplest of all the support methods. However, a considerable amount of land is required since the guy wires are widely spread apart. A rule of thumb for space required to erect a guy-supported flare is a circle on the ground with a radius equal to the height of the flare stack.[6]

7.2.5 Gas Seal

Air may tend to flow back into a flare stack due to wind or the thermal contraction of stack gases and create an explosion potential. To prevent this, a gas seal is typically installed in the flare stack. One type of gas seal (also referred to as a flare seal, stack seal, labyrinth seal, or gas barrier) is located below the flare tip to impede the flow of air back into the flare gas network. There are also "seals" which act as orifices in the top of the stack to reduce the purge gas volume for a given velocity and also interfere with the passage of air down the stack from the upper rim. These are known by the names "internal gas seal, fluidic-seal, and arrestor seal".[5] These seals are usually proprietary in design, and their presence reduces the operating purge gas requirements.

7.2.6 Burner Tip

The burner tip, or flare tip, is designed to give environmentally acceptable combustion of the vent gas over the flare system's capacity range. The burner tips are normally proprietary in design. Consideration is given to flame stability, ignition reliability, and noise suppression. The maximum and minimum capacity of a flare to burn a flared gas with a stable flame (not necessarily smokeless) is a function of tip design. Flame stability can be enhanced by flame holder retention devices incorporated in the flare tip inner circumference. Burner tips with modern flame holder designs can have a stable flame over a flare gas exit velocity range of 1 to 600 ft/sec.[2] The actual maximum capacity of a flare tip is usually limited by the vent stream pressure available to overcome the system pressure drop. Elevated flares diameters are normally sized to provide vapor velocities at maximum throughput of about 50 percent of the sonic velocity of the gas subject to the constraints of CFR 60.18.[l]

7.2.7 Pilot Burners

EPA regulations require the presence of a continuous flame. Reliable ignition is obtained by continuous pilot burners designed for stability and positioned around the outer perimeter of the flare tip. The pilot burners are ignited by an ignition source system, which can be designed for either manual or automatic actuation. Automatic systems are generally activated by a flame detection device using either a thermocouple, an infra-red sensor or, more rarely, (for ground flare applications) an ultra-violet sensor.[4]

7.2.8 Steam Jets

A diffusion flame receives its combustion oxygen by diffusion of air into the flame from the surrounding atmosphere. The high volume of fuel flow in a flare may require more combustion air at a faster rate than simple gas diffusion can supply. High velocity steam injection nozzles, positioned around the outer perimeter of the flare tip, increase gas turbulence in the flame boundary zones, drawing in more combustion air and improving combustion efficiency. For the larger flares, steam can also be injected concentrically into the flare tip.

The injection of steam into a flare flame can produce other results in addition to air entrainment and turbulence. Three mechanisms in which steam reduces smoke formation have been presented.[1] Briefly, one theory suggests that steam separates the hydrocarbon molecule, thereby minimizing polymerization, and forms oxygen compounds that burn at a reduced rate and temperature not conducive to cracking and polymerization. Another theory claims that water vapor reacts with the carbon particles to form CO, CO_2, and H_2, thereby removing the carbon before it cools and forms smoke. An additional effect of the steam is to reduce the temperature in the core of the flame and suppress thermal cracking.[5] The physical limitation on the quantity of steam that can be delivered and injected into the flare flame determines the smokeless capacity of the flare. Smokeless capacity refers to the volume of gas that can be combusted in a flare without smoke generation. The smokeless capacity is usually less than the stable flame capacity of the burner tip.

Significant disadvantages of steam usage are the increased noise and cost. Steam aggravates the flare noise problem by producing high-frequency jet noise. The jet noise can be reduced by the use of small multiple steam jets and, if necessary, by acoustical shrouding. Steam injection is usually controlled manually with the operator observing the flare (either directly or on a television monitor) and adding steam as required to maintain smokeless operation. To optimize steam usage infrared sensors are available that sense flare flame characteristics and adjust the steam flow rate automatically to maintain smokeless operation. Automatic control, based on flare gas flow and flame radiation, gives a faster response to the need for steam and a better adjustment of the quantity required. If a manual system is used, steam metering should be installed to significantly increase operator awareness and reduce steam consumption.

7.2.9 Controls

Flare system control can be completely automated or completely manual. Components of a flare system which can be controlled automatically include the auxiliary gas, steam injection, and the ignition system. Fuel gas consumption can be minimized by continuously measuring the vent gas flow rate and heat content (Btu/scf) and automatically adjusting the amount of auxiliary fuel to maintain the required minimum of 300 Btu/scf for steam-assisted flares. Steam consumption can likewise be minimized by controlling flow based on vent gas flow rate. Steam flow can also be controlled using visual smoke monitors. Automatic ignition panels sense the presence of a flame with either visual or thermal sensors and reignite the pilots when flameouts occur.

7.3 Design Procedures

Flare design is influenced by several factors, including the availability of space, the characteristics of the flare gas (namely composition, quantity, and pressure level) and occupational concerns. The sizing of flares requires determination of the required flare tip diameter and height. The emphasis of this section will be to size a steam-assisted elevated flare for a given application.

7.3.1 Auxiliary Fuel Requirement

The flare tip diameter is a function of the vent gas flow rate *plus* the auxiliary fuel and purge gas flow rate. The purge gas flow rate is very small relative to the vent gas and fuel flow rates, so it may be ignored when determining the tip diameter. The flow rate of the auxiliary fuel, if required, *is* significant, and must be calculated before the tip diameter can be computed.

Some flares are provided with auxiliary fuel to combust hydrocarbon vapors when a lean flare gas stream falls below the flammability range or heating value necessary to sustain a stable flame. The amount of fuel required, F, is calculated based on maintaining the vent gas stream net heating value at the minimum of 300 Btu/scf required by rules defined in the *Federal Register* (see next section):

$$Q\,B_v + F\,B_f = (Q + F)(300\ \text{Btu/scf}) \tag{7.2}$$

where

Q = the vent stream flow rate, scfm
B_v and B_f are the Btu/scf of the vent stream and fuel, respectively.

Rearranging gives:

$$F\ (\text{scfm}) = Q\,\frac{300 - B_v}{B_f - 300} \tag{7.3}$$

The annual auxiliary fuel requirement, F_a, is calculated by:

$$F_a(\text{Mscf/yr}) = (F\ \text{scfm})(60\text{min/hr})(8760\text{hr/yr}) = 526F \tag{7.4}$$

Typical natural gas has a net heating value of about 1,000 Btn/scf. Automatic control of the auxiliary fuel is ideal for processes with large fluctuations in VOC compositions. These flares are used for the disposal of such streams as sulfur tail gases and ammonia waste gases, as well as any low Btu vent streams.[2]

7.3.2 Flare Tip Diameter

Flare tip diameter is generally sized on a velocity basis, although pressure drop must also be checked. Flare tip sizing for flares used to comply with EPA air emission standards is governed by rules defined in the Federal Register (see 40 CFR 60.18). To comply with these requirements, the maximum velocity of a steam-assisted elevated flare is determined as follows:

Net Heating Value of Vent Stream B_v (Btu/scf)	Maximum Velocity V_{max} (ft/sec)
300	60
300 – 1,000	$\log_{10}(V_{max}) = (B_v + 1{,}214)/852$
>1,000	400

By determining the maximum allowed velocity, V_{max} (ft/sec), and knowing the total volumetric flow rate, Q_{tot} (acfm), including vent stream and auxiliary fuel gas, a minimum flare tip diameter, D_{min} (in), can be calculated. It is standard practice to size the flare so that the design velocity of flow rate Q_{tot}, is 80 percent of V_{max}, *i.e.*:

$$D_{min}(\text{in}) = 12\sqrt{\frac{\frac{4}{\pi}\,\frac{Q_{tot}}{60\ (\text{sec/min})}}{0.8\ V_{max}}} = 1.95\sqrt{\frac{Q_{tot}}{V_{max}}} \tag{7.5}$$

where

Q_{tot} = $Q + F$ (measured at stream temperature and pressure)

The flare tip diameter, D, is the calculated diameter, $D = D_{min}$, rounded up to the next commercially available size. The minimum flare size is 1 inch; larger sizes are available in 2-inch increments from 2 to 24 inches and in 6-inch increments above 24 inches. The maximum size commercially available is 90 inches.[5]

A pressure drop calculation is required at this point to ensure that the vent stream has sufficient pressure to overcome the pressure drop occurring through the flare system at maximum flow conditions. The pressure drop calculation is site specific but must take into account losses through the collection header and piping, the knock-out drum, the liquid seal, the flare stack, the gas seal, and finally the flare tip. Piping size should be assumed equal to the flare tip diameter. Schedule 40 carbon steel pipe is typically used. If sufficient pressure is not available, the economics of either a larger flare system (pressure drop is inversely proportional to the pipe diameter) or a mover such as a fan or compressor must be weighed. (Refer to Section 7.3.8 for typical pressure drop relationships.)

7.3.3 Flare Height

The height of a flare is determined based on the ground level limitations of thermal radiation intensity, luminosity, noise, height of surrounding structures, and the dispersion of the exhaust gases. In addition, consideration must also be given for plume dispersion in case of possible emission ignition failure. Industrial flares are normally sized for a maximum heat intensity of 1,500-2,000 Btu/hr-ft^2 when flaring at their maximum design rates.[1,2] At this heat intensity level, workers can remain in the area of the flare for a limited period only. If, however, operating personnel are required to remain in the unit area performing their duties, the recommended design flare radiation level excluding solar radiation is 500 Btu/hr-ft^2.[1] The intensity of solar radiation is in the range of 250-330 Btu/hr-ft^2.[1] Flare height may also be determined by the need to safely disperse the vent gas in case of flameout. The height in these cases would be based on dispersion modeling for the particular installation conditions and is not addressed here. The minimum flare height normally used is 30 feet.[5] Equation (7.6) by Hajek and Ludwig may be used to determine the minimum distance, *L*, required from the center of the flare flame and a point of exposure where thermal radiation must be limited.[1]

$$L^2\ (ft^2) = \frac{fR}{4\ K} \tag{7.6}$$

where

= fraction of heat intensity transmitted
f = fraction of heat radiated
R = net heat release (Btu/hr)
K = allowable radiation (500 Btu/hr-ft^2)

The conservative design approach used here ignores wind effects and calculates the distance assuming the center of radiation is at the base of the flame (at the flare tip), not in the center. It is also assumed that the location where thermal radiation must be limited is at the base of the flare. Therefore, the distance, *L*, is equal to the required flare stack height (which is a minimum of 30 feet). The *f* factor allows for the fact that not all the heat released in a flame can be released as radiation. Heat transfer is propagated through three mechanisms: conduction, convection, and radiation. Thermal radiation may be either absorbed, reflected, or transmitted. Since the atmosphere is not a perfect vacuum, a fraction of the heat radiated is not transmitted due to atmospheric absorption (humidity, particulate matter). For estimating purposes, however, assume all of the heat radiated is transmitted (*i.e.*, r = 1). The following is a summary of heat radiated from various gaseous diffusion flames:[1]

Gas	Flare Tip Diameter (in)	Fraction of Heat Radiated (*f*)
Hydrogen	<1	.10
	1.6	.11
	3.3	1.6
	8.0	1.5
	16.0	1.7
Butane	<1	.29
	1.6	.29
	3.3	.29
	8.0	.28
	16.0	.30
Methane	<1	.16
	1.6	.16
	3.3	.15
Natural Gas	8.0	.19
	16.0	.23

In general, the fraction of heat radiated increases as the stack diameter increases. If stream-specific data are not available, a design basis of f = 0.2 will give conservative results.[4] The heat release, R, is calculated from the flare gas flow rate, W, and the net heating value, B_v, as follows:

$$R \text{ (Btu/hr)} = (W \text{ lb/hr})(B_v \text{ Btu/lb}) \tag{7.8}$$

7.3.4 Purge Gas Requirement

The total volumetric flow to the flame must be carefully controlled to prevent low flow flashback problems and to avoid flame instability. Purge gas, typically natural gas, N_2, or $C0_2$, is used to maintain a minimum required positive flow through the system. If there is a possibility of air in the flare manifold, N_2, another inert gas, or a flammable gas must be used to prevent the formation of an explosive mixture in the flare system. To ensure a positive flow through all flare components, purge gas injection should be at the farthest upstream point in the flare transport piping.

The minimum continuous purge gas required is determined by the design of the stack seals, which are usually proprietary devices. Modern labyrinth and internal gas seals are stated to require a gas velocity of 0.001 to 0.04 ft/sec (at standard conditions).[6, 7, 8, 9, 10] Using the conservative value of 0.04 ft/sec and knowing the flare diameter (in), the annual purge gas volume, F_{pu}, can be calculated:

$$
\begin{aligned}
F_{pu}\ (\text{Mscf/yr}) &= (0.04\ \text{ft/sec}) \left(\frac{\frac{\pi D^2}{4}}{144}\ \text{ft}^2 \right) (3{,}600\ \text{sec/hr})(8{,}760\ \text{hr/yr}) \\
&= 6.88 D^2\ (\text{Mscf/yr})
\end{aligned}
\tag{7.9}
$$

There is another minimum flare tip velocity for operation without burn lock or instability. This minimum velocity is dependent on both gas composition and diameter and can range from insignificant amounts on small flares to 0.5 ft/sec on greater than 60-inch diameter units.[5]

Purge gas is also required to clear the system of air before startup, and to prevent a vacuum from pulling air back into the system after a hot gas discharge is flared. (The cooling of gases within the flare system can create a vacuum.) The purge gas consumption from these uses is assumed to be minor.

7.3.5 Pilot Gas Requirement

The number of pilot burners required depends on flare size and, possibly, on flare gas composition and wind conditions. Pilot gas usage is a function of the number of pilot burners required to ensure positive ignition of the flared gas, of the design of the pilots, and of the mode of operation. The average pilot gas consumption based on an energy-efficient model is 70 scf/hr (of typical 1000 Btu per scf gas) per pilot burner.[6, 7, 8, 9, 10] The number of pilot burners, N, based on flare size is:[6, 7, 8, 9, 10]

Flare Tip Diameter (in)	**Number of Pilot Burners (*N*)**
1-10	1
12-24	2
30-60	3
>60	4

The annual pilot gas consumption, F_{pi} is calculated by:

$$F_{pi}\ (\text{Mscf/yr}) = (70\ \text{scf/hr})(N)(8{,}760\ \text{hr/yr}) = 613\ N \tag{7.10}$$

7.3.6 Steam Requirement

The steam requirement depends on the composition of the vent gas being flared, the steam velocity from the injection nozzle, and the flare tip diameter. Although some gases can be flared smokelessly without any steam, typically 0.01 to 0.6 pound of steam per pound of flare gas is required.[6, 7, 8, 9, 10] The ratio is usually estimated from the molecular weight of the gas, the carbon-to-hydrogen ratio of the gas, or whether the gas is saturated or unsaturated. For example, olefins, such as propylene, require higher steam ratios than would paraffin hydrocarbons to burn smokelessly.[2]

In any event, if a proprietary smokeless flare is purchased, the manufacturer should be consulted about the minimum necessary steam rate. A small diameter flare tip (less than 24 inches) can use steam more effectively than a large diameter tip to mix air into the flame and promote turbulence.[2] For a typical refinery, the average steam requirement is typically 0.25 lb/lb, with this number increasing to 0.5 lb/lb in chemical plants where large quantities of unsaturated hydrocarbons are flared.[10]

For general consideration, the quantity of steam required, S, can be assumed to be 0.4 pounds of steam per pound of flare gas, W. Using a 0.4 ratio, the amount of steam required is:

$$S\ (\text{lbs/yr}) = 0.4(W\ \text{lb/yr})(8{,}760\ \text{hr/yr}) = 3{,}500(W\ \text{lbs/hr}) \tag{7.11}$$

Operating a flare at too high a steam-to-gas ratio is not only costly, but also results in a lower combustion efficiency and a noise nuisance. The capacity of a steam-assisted flare to burn smokelessly may be limited by the quantity of steam that is available.

7.3.7 Knock-out Drum

As explained previously, the knock-out drum is used to remove any liquids that may be in the vent stream. Two types of drums are used: horizontal and vertical. The economics of vessel design influences the choice between a horizontal and a vertical drum. When a large liquid storage vessel is required and the vapor flow is high, a horizontal drum is usually more economical. Vertical separators are used when there is small liquid load, limited plot space, or where ease of level control is desired. It is assumed here that the drum is not sized for emergency releases and that liquid flow is minimal. Flares designed to control continuous vent streams generally have vertical knockout drums, whereas emergency flares typically have horizontal vessels. The procedure described below applies to *vertical* drums exclusively. A typical vertical knock-out drum is presented in Figure 7.2.

Liquid particles will separate when the residence time of the vapor is greater than the time required to travel the available vertical height at the dropout velocity of the liquid particles, *i.e.*, the velocity is less than the dropout velocity. In addition, the vertical gas velocity must be sufficiently low to permit the liquid droplets to fall. Since flares are designed to handle small-sized liquid droplets, the allowable vertical velocity is based on separating droplets from 300 to 600 micrometers in diameter.[1] The dropout velocity, *U*, of a particle in a stream, or the maximum design vapor velocity, is calculated as follows:[11]

$$U\ (\mathrm{ft/sec}) = G\sqrt{\frac{\rho_l - \rho_v}{\rho_v}} \qquad (7.12)$$

where

G	=	design vapor velocity factor
p_l and p_v	=	liquid and vapor densities, lb/ft^3

Note that in most cases,

$$\frac{\rho_l - \rho_v}{\rho_v} \approx \frac{\rho_l}{\rho_v}$$

The design vapor velocity factor, *G*, ranges from 0.15 to 0.25 for vertical gravity separators at 85% of flooding.[11]

Once the maximum design vapor velocity has been determined the minimum vessel cross-sectional area, *A*, can be calculated by:

$$A\ (\mathrm{ft}^2) = \frac{Q_a\ \mathrm{ft}^3/\mathrm{min}}{(60\ \mathrm{sec/min})(U\ \mathrm{ft/sec})} \qquad (7.12)$$

where Q_n is the vent stream flow in actual ft^3/min, or *Q* adjusted to the vent stream temperature and pressure.

The vessel diameter, d_{min}, is then calculated by:

$$(d_{min}\ (\text{in}) = (12\ \text{in/ft})\sqrt{\frac{4}{\pi}(A\ \text{ft}^2)} = 13.5\sqrt{A} \tag{7.13}$$

In accordance with standard head sizes, drum diameters in 6-inch increments are assumed so:

$$d = d_{min} \text{ rounded to the next largest size} \tag{7.14}$$

Some vertical knockout drums are sized as cyclones and utilize a tangential inlet to generate horizontal separating velocities. Vertical vessels sized exclusively on settling velocity (as in the paragraph above) will be larger than those sized as cyclones.[5]

The vessel thickness, *t*, is determined based on the following:[13]

Diameter, *d* (inches)	**Thickness, *t* (inches)**
d< 36	0.25
36 ≤d< 72	0.37
72 ≤d< 108	50.5
108 ≤d< 144	0.75
d≥ 144	1.0

Proper vessel height, *h*, is usually determined based on required liquid surge volume. The calculated height is then checked to verify that the height-to-diameter ratio is within the economic range of 3 to 5.[11] For small volumes of liquid, as in the case of continuous VOC vent control, it is necessary to provide more liquid surge than is necessary to satisfy the h/d>3 condition. So for purposes of flare knock-out drum sizing:

$$h\ (\text{in}) = 3d \tag{7.15}$$

7.3.8 Gas Mover System

The total system pressure drop is a function of the available pressure of the vent stream, the design of the various system components, and the flare gas flow rate. The estimation of actual pressure drop requirements involves complex calculations based on the specific system's vent gas properties and equipment used. For the purposes of this section, however, approximate values can be used. The design pressure drop through the flare tip can range from ≈ 0.1 to 2 psi with the following approximate pressure drop relationships:[5]

Gas seal:	1 to 3 times flare tip pressure drop
Stack:	0.25 to 2 times flare tip pressure drop
Liquid seal and Knock-out drum:	1 to 1.5 times flare tip pressure drop *plus* pressure drop due to liquid depth in the seal, which is normally 0.2 to 1.5 psi.
Gas collection system:	calculated based on diameter, length, and flow. System is sized by designer to utilize the pressure drop available and still leave a pressure at the stack base of between 2 and 10 psi.

Typical total system pressure drop ranges from about 1 to 25 psi.[5]

7.4 Estimating Total Capital Investment

The capital costs of a flare system are presented in this section and are based on the design/sizing procedures discussed in Section 7.3. The costs presented are in **March 1990** dollars.*

Total capital investment, TCI, includes the equipment costs, EC, for the flare itself, the cost of auxiliary equipment, the cost of taxes, freight, and instrumentation, and all direct and indirect installation costs.

The capital cost of flares depends on the degree of sophistication desired (*i.e.*, manual vs automatic control) and the number of appurtenances selected, such as knock-out drums, seals, controls, ladders, and platforms. The basic support structure of the flare, the size and height, and the auxiliary equipment are the controlling factors in the cost of the flare. The capital investment will also depend on the availability of utilities such as steam, natural gas, and instrument air.

The total capital investment is a battery limit cost estimate and does not include the provisions for bringing utilities, services, or roads to the site, the backup facilities, the land, the research and development required, or the process piping and instrumentation interconnections that may be required in the process generating the waste gas. These costs are based on a new plant installation; no retrofit cost considerations such as demolition, crowded construction working conditions, scheduling construction with production activities, and long interconnecting piping are included. These factors are so site-specific that no attempt has been made to provide their costs.

*For information on escalating these prices to more current dollars, refer to the EPA report <u>Escalation Indexes for Air Pollution Control Costs</u> and updates thereto, all of which are installed on the OAQPS Technology Transfer Network (CTC Bulletin Board).

7.4.1 Equipment Costs

Flare vendors were asked to provide budget estimates for the spectrum of commercial flare sizes. These quotes [6, 7, 8, 9, 10] were used to develop the equipment cost correlations for flare units, while the cost equations for the auxiliary equipment were based on references [12] and [13] (knock-out drums) and [14] and [15] (piping). The expected accuracy of these costs is ± 30% (*i.e.*, "study" estimates). Keeping in mind the height restrictions discussed in Section 7.2.4, these cost correlations apply to flare tip diameters ranging from 1 to 60 inches and stack heights ranging from 30 to 500 feet. The standard construction material is carbon steel except when it is standard practice to use other materials, as is the case with burner tips.

The flare costs, C_F presented in Equations 7.16 through 7.18 are calculated as a function of stack height, L (ft) (30 ft minimum), and tip diameter, D (in), and are based on support type as follows:

Self Support Group:

$$C_F\ (\$) = (78.0 + 9.14D + 0.749L)^2 \tag{7.16}$$

Guy Support Group:

$$C_F\ (\$) = (103 + 8.68D + 0.470L)^2 \tag{7.17}$$

Derrick Support Group:

$$C_F\ (\$) = (76.4 + 2.72D + 1.64L)^2 \tag{7.18}$$

The equations are least-squares regression of cost data provided by different vendors. It must be kept in mind that even for a given flare technology (*i.e.*, elevated, steam-assisted), design and manufacturing procedures vary from vendor to vendor, so that costs may vary. Once a study estimate is completed, it is recommended that several vendors be solicited for more detailed cost estimates.

Each of these costs includes the flare tower (stack) and support, burner tip, pilots, utility (steam, natural gas) piping from base, utility metering and control, liquid seal, gas seal, and galvanized caged ladders and platforms as required. Costs are based on carbon steel construction, except for the upper four feet and burner tip, which are based on 310 stainless steel.

The gas collection header and transfer line requirements are very site specific and depend on the process facility where the emission is generated and on where the flare is located. For the purposes of estimating capital cost it is assumed that the transfer line will be the same diameter as the flare tip[6] and will be 100 feet long. Most installations will require much more extensive piping, so 100 feet is considered a minimum.

The costs for vent stream piping, C_p, are presented separately in Equation 7.19 or 7.20 and are a function of pipe, or flare, diameter D.[15]

$$C_p\ (\$) = 127 D^{1.21}\ (\text{where } 1'' < D < 24'') \tag{7.19}$$

$$C_p\ (\$) = 139 D^{1.07}\ (\text{where } 30'' < D < 60'') \tag{7.20}$$

The costs, C_p, include straight, Schedule 40, carbon steel pipe only, are based on 100 feet of piping, and are directly proportional to the distance required.

The costs for a knock-out drum, C_K, are presented separately in Equation 7.21 and are a function of drum diameter, d (in), and height, h (in).[12, 13]

$$C_K\ (\$) = 14.2\left[dt\ (h + 0.812 d)\right]^{0.737} \tag{7.21}$$

where t is the vessel thickness, in inches, determined based on the diameter.

Flare system equipment cost, EC, is the total of the calculated flare, knock-out drum, and piping costs.

$$EC\ (\$) = C_F + C_K + C_p \tag{7.22}$$

Purchased equipment costs, PEC, is equal to equipment cost, EC, plus factors for ancillary instrumentation (*i.e.*, control room instruments) (.10), sales taxes (0.03), and freight (0.05) or,

$$\text{PEC}\ (\$) = \text{EC}\ (1 + 0.10 + 0.03 + 0.05) = 1.18\ \text{EC} \tag{7.23}$$

7.4.2 Installation Costs

The total capital investment, TCI, is obtained by multiplying the purchased equipment cost, PEC, by an installation factor of 1.92.

$$\text{TCI}\ (\$) = 1.92\ \text{PEC} \tag{7.24}$$

These costs were determined based on the factors in Table 7.1. The bases used in calculating annual cost factors are given in Table 7.2. These factors encompass direct and indirect installation costs. Direct installation costs cover foundations and supports, equipment handling and erection, piping, insulation, painting, and electrical. Indirect installation costs cover engineering, construction and field expenses, contractor fees, start-up, performance testing, and contingencies. Depending on the site conditions, the installation costs for a given flare could deviate significantly from costs generated by these average factors. Vatavuk and Neveril provide some guidelines for adjusting the average installation factors to account for other-than-average installation conditions .[16]

7.5 Estimating Total Annual Costs

The total annual cost, TAC, is the sum of the direct and indirect annual costs. The bases used in calculating annual cost factors are given in Table 7.2

7.5.1 Direct Annual Costs

Direct annual costs include labor (operating and supervisory), maintenance (labor and materials), natural gas, steam, and electricity. Unless the flare is to be dedicated to one vent stream and specific on-line operating factors are known, costs should be calculated based on a continuous operation of 8,760 hr/yr and expressed on an annual basis. Flares serving multiple process units typically run continuously for several years between maintenance shutdowns.

Operating labor is estimated at 630 hours annually.[3] A completely manual system could easily require 1,000 hours. A standard supervision ratio of 0.15 should be assumed.

Maintenance labor is estimated at 0.5 hours per 8-hour shift. Maintenance materials costs are assumed to equal maintenance labor costs. Flare utility costs include natural gas, steam, and electricity.

Flare systems can use natural gas in three ways: in pilot burners that fire natural gas, in combusting low Btu vent streams that require natural gas as auxiliary fuel, and as purge gas. The total natural gas cost, C_f, to operate a flare system includes pilot, C_{pi}, auxiliary fuel, C_a, and purge costs, C_{pu}:

$$C_f \ (\$/yr) = C_{pi} + C_a + C_{pu} \tag{7.25}$$

where, C_{pi} is equal to the annual volume of pilot gas, F_{pi}, multiplied by the cost per scf, *i.e.*:

$$C_{pi} \ (\$/yr) = (F_{pi} \ scf/yr)(\$/scf) \tag{7.26}$$

C_a and C_{pu} are similarly calculated.

Steam cost (C_s) to eliminate smoking is equal to the annual steam consumption 8,760 *S* multiplied by the cost per lb, *i.e.*:

$$C_s\ (\$/yr) = (8{,}760\ hr/yr)(S\ lb/hr)(\$/lb) \qquad (7.27)$$

The use of steam as a smoke suppressant can represent as much as 90% or more of the total direct annual costs.

7.5.2 Indirect Annual Costs

The indirect (fixed) annual costs include overhead, capital recovery, administrative (G & A) charges, property taxes, and insurance. Suggested indirect annual cost factors are presented in Table 7.2.

Overhead is calculated as 60% of the total labor (operating, maintenance, and supervisory) and maintenance material costs. Overhead cost is discussed in Chapter 2 of this *Manual*.

Table 7.1: Capital Cost Factors for Flare Systems

Cost Item	Factor
Direct Costs	
Purchased equipment costs	
Flare system, EC	As estimated, A
Instrumentation	0.10 A
Sales taxes	0.03 A
Freight	0.05 A
Purchased equipment cost, PEC	B = 1.18 A
Direct installation costs	
Foundations & supports	0.12 B
Handling & erection	0.40 B
Electrical	0.01 B
Piping	0.02 B
Insulation	0.01 B
Painting	0.01 B
Direct installation costs	0.57 B
Site preparation	As required, SP
Buildings	As required, Bldg.
Total Direct Costs, DC	1.57 B + SP + Bldg.
Indirect Annual Costs, DC	
Engineering	0.10 B
Construction and Field expenses	0.10 B
Contractor fees	0.10 B
Start-up	0.01 B
Performance test	0.01 B
Contingencies	0.03 B
Total Indirect Costs, IC	0.35 B
Total Capital Investment = DC + IC	1.92 B + SP + Bldg.

The system capital recovery cost, CRC, is based on an estimated 15-year equipment life. (See Chapter 2 of this *Manual* for a thorough discussion of the capital recovery cost and the variables that determine it.) For a 15-year life and an interest rate of 7%, the capital recovery factor is 0.1098. The system capital recovery cost is the product of the system capital recovery factor, CRF, and the total capital investment, TCI, or:

$$\mathit{CRC}\ (\$/yr) = CRF \times TCI = 0.1098 \times TCI \tag{7.28}$$

As shown in Table 7.2, G & A, taxes, and insurance can be estimated at 2%, 1%, and 1% of the total capital investment, TCI, respectively.

7.6 Example Problem

The example problem described in this section shows how to apply the flare sizing and costing procedures to the control of a vent stream associated with the distillation manufacturing of methanol.

7.6.1 Required Information for Design

The first step in the design procedure is to determine the specifications of the vent gas to be processed. The minimum information required to size a flare system for estimating costs are the vent stream:

Volumetric or mass flow rate
Heating value or chemical composition
Temperature
System pressure
Vapor and liquid densities

In addition the following are needed to calculate direct annual costs.

Labor costs
Fuel costs
Steam costs

Vent stream parameters and cost data to be used in this example problem are listed in Table 7.3.

Table 7.2: Suggested Annual Cost Factors for Flare Systems

Cost Item	Factor
<u>Direct Annual Costs, DC</u>	
Operating labor{3}	
Operator	630 man-hours/year
Supervisor	15% of operator
Operating materials	—
Maintenance	
Labor	½ hour per shift
Material	100% of maintenance labor
Utilities	
Electricity	All utilities equal to:
Purge gas	(Consumption rate) x
Pilot gas	(Hours/yr) x (unit cost)
Auxiliary fuel	
Steam	
<u>Indirect Annual Costs, IC</u>	
Overhead	60% of total labor and material costs
Administrative charges	2% of Total Capital Investment
Property tax	1% of Total Capital Investment
Insurance	1% of Total Capital Investment
Capital recovery[a]	0.1315 x Total Capital Investment
Total Annual Cost	Sum of Direct and Indirect Annual Costs

[a]See Chapter 2.

Table 7.3: Example Problem Data

Vent Stream Parameters	
Flow rate	63.4 acfm[a]
	399.3 lb/hr
Heat content	449 Btu/scf[b]
System pressure	10 psig[c]
Temperature	90 °F
Liquid density[17]	49.60 lb/ft^3[d]
Vapor density[17]	0.08446 lb/ft^3[d]
Cost Data (March 1990)[18,19]	
Operating hours	8,760 hrs/yr
Natural gas	3.03 $/1000 scf
Steam	4.65 $/1000 lbs
Operating labor	15.64 $/hr
Maintenance labor	17.21 $/hr

[a]Measured at *flare tip*. Flow rate has been adjusted to account for drop in pressure from 10 psig at source to 1 psig at flare tip.
[b]Standard conditions: 77°F, 1 atmosphere.
[c]Pressure at source (gas collection point). Pressure at flare tip is lower: 1 psig.
[d]Measured at standard conditions.

7.6.2 Capital Equipment

The first objective is to properly size a steam-assisted flare system to effectively destroy 98% of the VOC (methanol) in the vent gas stream. Using the vent stream parameters and the design procedures outlined in Section 7.3, flare and knock-out drum heights and diameters can be determined. Once equipment has been specified, the capital costs can be determined from equations presented in Section 7.4.1.

7.6.2.1 Equipment Design

The first step in flare sizing is determining the appropriate flare tip diameter. Knowing the net (lower) heating value of the vent stream, the maximum allowed velocity can be calculated from the Federal Register requirements. Since the heating value is in the range of 300 to 1,000 Btu/scf, the maximum velocity, V_{max}, is determined by Equation 7.1.

$$\log_{10} V_{max} = \frac{449 \text{ Btu/scf} + 1{,}214}{852}$$
$$= 1.95$$

so,

$$V_{max} = 89.5 \text{ ft/sec}$$

Because the stream heating value is above 300 Btu/scf, no auxiliary fuel is required. Hence, Q_{tot} equals the vent stream flow rate. Based on Q_{tot} and V_{max}, the flare tip diameter can be calculated using Equation 7.5.

$$D_{min} = 1.95 \sqrt{\frac{Q_{tot}}{V_{max}}}$$
$$= 1.95 \sqrt{\frac{63.4 \text{ acfm}}{89.5 \text{ ft/sec}}}$$
$$= 1.64 \text{ in}$$

The next largest commercially available standard size of 2 inches should he selected for *D*.

The next parameter to determine is the required height of the flare stack. The heat release from the flare is calculated using Equation 7.7.

$$R \text{ (Btu/hr)} = (W \text{ lb/hr})(B_v \text{ Btu/lb})$$

First the heat of combustion, or heating value, must be converted from Btu/scf to Btu/lb. The vapor density of the vent stream at standard temperature and pressure is 0.08446 lb/scf.

So,

$$B_v = \frac{449 \text{ Btu/scf}}{0.08446 \text{ lb/scf}} = 5316 \text{ Btu/lb}$$

and,

$$R = (399.3 \text{ lb/hr})(5{,}316 \text{ Btu/lb}) = 2{,}123{,}000 \text{ Btu/hr}$$

Substituting *R* and appropriate values for other variables into Equation 7.6:

$$\begin{aligned} L^2 (\text{ft}^2) &= \frac{fR}{4 K} \\ &= \frac{(1)(0.2)(2{,}123{,}000 \text{ Btu/hr})}{4 (500 \text{ Btu/hr-ft}^2)} \\ &= 68 \text{ ft}^2 \end{aligned}$$

gives a height of *L* = 8.2 ft. The smallest commercially available flare is 30 feet, so *L* = 30 ft.

Next the knock-out drum must be sized. Assuming a design vapor velocity factor, *G*, of 0.20, and substituting the vapor and liquid densities of methanol into Equation 7.11 yields a *maximum* velocity of:

$$\begin{aligned} U &= G\sqrt{\frac{{}_{l} - {}_{v}}{{}_{v}}}, \text{ ft/sec} \\ &= 0.20\sqrt{\frac{49.60 - 0.08446}{0.08446}} \\ &= 4.84 \text{ ft/sec} \end{aligned}$$

Given a vent gas flow rate of 63.4 scfm, the *minimum* vessel cross-sectional, diameter is calculated by Equation 7.12:

$$
\begin{aligned}
A &= \frac{Q_a \text{ acfm}}{(60 \text{ sec/min})(U \text{ ft/sec})} \\
&= \frac{63.4}{(60)(4.84)} \\
&= 0.218 \text{ ft}^2
\end{aligned}
$$

This results in a minimum vessel diameter of:

$$
\begin{aligned}
d_{\min} &= 13.5\sqrt{A} \\
&= 13.5\sqrt{0.218} \\
&= 6.3 \text{ inches}
\end{aligned}
$$

The selected diameter, *d*, rounded to the next largest 6 inches is 12 inches. Using the rule of the height to diameter ratio of three gives a vessel height of 36 inches, or 3 feet.

7.6.2.2 Equipment Costs

Once the required flare tip diameter and stack height have been determined the equipment costs can be calculated. Since the height is 30 feet, the flare will be self-supporting. The costs are determined from Equation 7.16.

$$
\begin{aligned}
C_F &= (78.0 + 9.14D + 0.749L)^2 \\
&= [78.0 + 9.14(2 \text{ inches}) + 0.749(30 \text{ ft})]^2 \\
&= \$14{,}100
\end{aligned}
$$

Knock-out drum costs are determined using Equation 7.21, where *t* is determined from the ranges Presented in Section 7.3.7. Substituting 0.25 for *t*:

$$
\begin{aligned}
C_K &= 14.2[dt\ (h + 0.812d)]^{0.737} \\
&= 14.2[(12)(0.25)(36 + 0.812(12))]^{0.737} \\
&= \$530
\end{aligned}
$$

Transport piping costs are determined using Equation 7.19.

$$
\begin{aligned}
C_p &= 127D^{1.21} \\
&= 127(2)^{1.21} \\
&= \$290
\end{aligned}
$$

The total auxiliary equipment cost is the sum of the knock-out drum and transport piping costs, or $530 + $290 = $820.

The total capital investment is calculated using the factors given in Table 7.1. The calculations are shown in Table 7.4. Therefore:

$$\text{Purchased Equipment Cost} = \text{"B"} = 1.18 \times A$$
$$= 1.18 \times (14{,}920) = \$17{,}610$$

And:

$$\text{Total Capital Investment (rounded)} = 1.92 \times B$$
$$= 1.92 \times (17{,}610) = \$33{,}800.$$

Table 7.4: Capital Costs for Flare Systems
Example Problem

Cost Item	Cost
Direct Costs	
Purchased equipment costs	
Flare (self supporting)	\$14,100
Auxiliary equipment[a]	820
Sum = A	\$14,920
Instrumentation, 0.1A	1,490
Sales taxes, 0.03A	450
Freight, 0.05A	750
Purchased equipment cost, B	\$17,610
Direct installation costs	
Foundation and supports, 0.12B	2,110
Handling & erection, 0.40B	7,040
Electrical, 0.01B	180
Piping, 0.02B	350
Insulation, 0.01B	180
Painting, 0.01B	180
Direct installation cost	\$10,040
Site preparation	—
Facilities and buildings	—
Total Direct Cost	\$27,650
Indirect Costs (installation)	
Engineering, 0.10B	1,760
Construction and field expenses, 0.10B	1,760
Contractor fees, 0.10B	1,760
Start-up, 0.01B	180
Performance test, 0.01B	180
Contingencies, 0.03B	530
Total Indirect Cost	\$6,170
Total Capital Investment (rounded)	\$33,800

[a] Includes costs for knock-out drum and transport piping.

7.6.3 Operating Requirements

Operating labor is estimated at 630 hours annually with supervisory labor at 15% of this amount. Maintenance labor is estimated at 1/2 hour per shift. Maintenance material costs are assumed to be equal to maintenance labor costs.

As stated above, since the heat content of the example stream is above 300 Btu/scf (*i.e.*, 449 Btu/scf) no auxiliary fuel is needed. Natural gas is required, however, for purge and pilot gas. Purge gas requirements are calculated from Equation 7.8.

$$F_{pu} = 6.88D^2 = 6.88(2)^2 = 27.5 \text{ Mscf/yr}$$

Since the flare tip diameter is less than 10 inches, pilot gas requirements are based on one pilot burner, (see Section 7.3.5) and are calculated by Equation 7.9.

$$F_{pi} = 613N$$

When N = 1,

$$F_{pi} = 613 \text{ Mscf/yr}$$

Steam requirements are calculated from Equation 7.10:

$$S \text{ (lb/yr)} = 3{,}500\ W$$

Inserting the methanol mass flow rate of 399.3 lb/hr yields:

$$\begin{aligned} S &= (3{,}500)(399.3 \text{ lb/hr}) \\ &= 1{,}400 \text{ Mlb/yr} \end{aligned}$$

7.6.4 Total Annual Costs

The sum of the direct and indirect annual costs yields a total annual cost of $61,800. Table 7.5 shows the calculations of the direct and indirect annual costs for the flare system as calculated from the factors in Table 7.2. Direct costs include labor, materials, and utilities. Indirect costs are the fixed costs allocated to the project, including capital recovery costs and such costs as overhead, insurance, taxes, and administrative charges.

Electrical costs of a mover system (fan, blower, compressor) would have to be included if the vent stream pressure was not sufficient to overcome the flare system pressure drop. In this example case, the pressure is assumed to be adequate.

Table 7.5: Annual Costs for Flare System
Example problem

Cost Item	Calculations	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	$\frac{630\text{ h}}{\text{year}} \times \frac{\$15.64}{\text{h}}$	$ 9,850
Supervisor	15% of operator = 0.15 x 9,850	1,480
Operating materials		----
Maintenance		
Labor	$\frac{0.5\text{ h}}{\text{shift}} \times \frac{\text{shift}}{8\text{ h}} \times \frac{8{,}760\text{h}}{\text{yr}} \times \frac{\$17.21}{\text{h}}$	9,420
Material	100% of maintenance labor	9,420
Utilities		
Electricity		----
Purge gas	$\frac{27.5\text{ Mscf}}{\text{yr}} \times \frac{\$3.03}{\text{Mscf}}$	80
Pilot gas	$\frac{613\text{ Mscf}}{\text{yr}} \times \frac{\$3.03}{\text{Mscf}}$	1,860
Steam	$\frac{1{,}400 \times 10^3\text{lb}}{\text{yr}} \times \frac{\$4.65}{10^3\text{lb}}$	6,510
Total DC (rounded)		$38,600
Indirect Annual Costs, IC		
Overhead	60% of total labor and material costs = 0.6(9,850 + 1,480 + 9,420 + 9,420)	18,100
Administrative charges	2% of Total Capital Investment = 0.02 ($33,800)	680
Property tax	1% of Total Capital Investment = 0.01 ($33,800)	340
Insurance	1% of Total Capital Investment = 0.01 ($33,800)	340
Capital recovery[a]	0.1098 x $33,800	3,710
Total IC (rounded)		23,200
Total Annual Cost (rounded)		$61,800

[a]The capital recovery cost factor, CRF, is a function of the flare equipment life and the opportunity cost of the capital (i.e. interest rate). For example, for a 15 year equipment life and 7% interest rate, CRF = 0.1098.

7.7 Acknowledgments

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- NAO Incorporated (Philadelphia, PA)
- Peabody Engineering Corporation (Stamford, CT)
- Piedmont HUB, Incorporated (Raleigh, NC)

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OCD Exhibit 42

PRO Fact Sheet No. 403

Partner Reported Opportunities (PROs) for Reducing Methane Emissions

Use Inert Gases and Pigs to Perform Pipeline Purges

Technology/Practice Overview

Description

When pipeline segments are taken out of service for operational or maintenance purposes, it is common practice to depressurize the pipeline and vent the natural gas to the atmosphere. To prevent these emissions, Partners reported using pigs and inert gas to purge pipelines.

In implementing this practice, a pig is inserted into the isolated section of pipeline. Inert gas is then pumped in behind the pig, which pushes natural gas through to the product line. At the appropriate shutoff point, the pig is caught in a pig trap and the pipeline blocked off. Once the pipeline is "gas-free" the inert gas is vented to the atmosphere.

Operating Requirements

Requires existing pig-launch and pig trap facilities and a mobile nitrogen supply.

Applicability

This practice applies to all pipeline segments that are being taken out of service for operational or maintenance purposes.

Methane Emissions

The amount of avoided methane emissions is a function of the pipeline diameter, length, and pressure. Based on the *Pipeline Rules of Thumb Handbook*, Fourth Edition, (p. 270), the amount of gas saved by the unit of application is 90 Mcf per year per two miles of 10-inch diameter pipeline. One Partner reported avoiding 538 Mcf of methane for 6 purges by using pigs and inert gas.

- [ ] Compressors/Engines
- [ ] Dehydrators
- [ ] Directed Inspection & Maintenance
- [x] Pipelines
- [ ] Pneumatics/Controls
- [ ] Tanks
- [ ] Valves
- [ ] Wells
- [ ] Other

Applicable Sector(s)

- [ ] Production
- [x] Processing
- [x] Transmission
- [x] Distribution

Other Related Documents:

Inject Blowdown Gas into Low Pressure Mains or Fuel Gas System, PRO No. 401

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*90 Mcf per two miles of 10-inch diameter pipeline*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	90 Mcf	$670	$0	$500	9 Months
$5.00/Mcf	90 Mcf	$480	$0	$500	13 Months
$3.00/Mcf	90 Mcf	$290	$0	$500	21 Months

** Whole gas savings are calculated using a conversion factor of 94% methane in pipeline quality natural gas.*

Additional Benefits

- Safety of pipeline system and operators

Use Inert Gases and Pigs to Perform Pipeline Purges (Cont'd)

Economic Analysis

Basis for Costs and Emissions Savings

Methane emissions reductions of 90 Mcf per year apply to purging 2 miles of 10-inch diameter pipeline with nitrogen at 280-psi pressure, once per year.

The economics of this PRO are based on nitrogen at $5 per Mcf up to 50 miles from the source to the pipeline location and 2 operators working 8 hours each (labor rate of $25 per hour). There is no capital equipment required.

Discussion

This practice employs inert gases in combination with a pig to prevent venting of a valuable product when taking a pipeline segment off-line for operational or maintenance purposes. Though it can be cost-effective, safety, not methane savings, is the primary reason for using pigs and inert gas to purge pipelines.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

OCD Exhibit 43

Lessons Learned
from Natural Gas STAR Partners

Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance

Executive Summary

Operators of natural gas pipeline systems routinely reduce line pressure and discharge gas from pipeline sections to ensure safe working conditions during maintenance and repair activities. Typically, operators block the smallest possible linear section of the pipeline and depressurize it by venting gas to the atmosphere. In 2004, an estimated 12 billion cubic feet (Bcf) of methane was vented to the atmosphere during routine maintenance and pipeline upsets.

Using pump-down techniques to lower gas line pressure before performing maintenance and repair activities is an effective way to reduce emissions and yield significant economic savings. Pipeline pump-down techniques involve using in-line compressors either alone or in sequence with portable compressors. Using in-line compressors is almost always justifiable because there are no capital costs, and payback is immediate. The cost-effectiveness of also using a portable compressor to increase gas recovery, however, depends greatly on site-specific factors and operating costs.

Another alternative is to install an ejector. An ejector is a venturi nozzle that uses high-pressure gas as motive fluid to draw suction on a lower pressure gas source, discharging into an intermediate pressure gas stream. The ejector can be installed on vent connections up and down stream of a partly closed valve, or between the discharge and suction of a compressor which creates the necessary pressure differential.

Regardless of the pump-down technique selected, emission reductions are directly proportional to how much pipeline pressure is reduced before venting occurs. On average, up to 90 percent of the gas in the pipeline can be recovered for sale instead of being emitted. Pipeline pump-down techniques are most economical for larger volume, higher pressure gas lines and work most effectively for planned maintenance activities and cases in which sufficient manifolding exists to connect a portable compressor.

Many Natural Gas STAR Partners have realized significant economic savings by using pump-down techniques. In 2004, Natural Gas STAR transmission Partners saved a total of 4.1 Bcf of gas using pump-down techniques. Based on a value of gas saved of $7.00/Mcf, that equals more than $28 million saved.

Technology Background

Natural gas transmission, distribution, and production companies transport methane and other light hydrocarbons via pressurized gas pipelines. These pipelines can require repairs or maintenance throughout their lifetime as a result of interior and exterior corrosion, gasket and weld leaks, failures of defective materials, and damage caused by external factors. Pipeline repairs fall into four general categories:

★ Class 1 non-emergency repairs that do not involve complete service interruption.

★ Class 2 non-emergency repairs that require complete service interruption.

★ Class 3 emergency repairs that require complete service interruption.

★ Class 4 large-scale projects where new pipe is being

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf)[a]	Value of Natural Gas Savings ($)			Implementation Cost ($)	Payback (Months)[b]		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Pump down gas pipelines before maintenance	200,000 per year	$600,000 per year	$1,000,000 per year	$1,400,000 per year	$98,757	2	2	1

General Assumptions:
[a] Based on experiences reported annually by Natural Gas STAR Partners, which varied considerably. Factors impacting the volume of gas saved and the cost of implementation include pipeline length and pressure, compressor type, and number of locations or pump-down instances. Data includes both in-line and portable compressor reported results.
[b] Payback period for in-line compressors is immediate because there are no capital costs.

Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance
(Cont'd)

run parallel to existing pipe and require service interruption.

Pipeline repairs and maintenance activities typically require depressurizing the pipeline to remove gas from the affected section of pipe and ensure safe working conditions. One approach to depressurization is to block off the impacted pipeline segment and vent the gas in that segment to the atmosphere. Alternatively, operators can use pump-down techniques to lower the gas-line pressure before venting. Pump-down techniques are the preferable alternative because they make more gas available for sale and reduce methane emissions.

In implementing pipeline pump-down techniques, operators can use two types of compressors to reduce pipeline pressure: in-line compressors and portable compressors. Depending on the situation, operators can use in-line compressors alone or with portable compressors.

- ★ **Using in-line pipeline compressors to draw down the pressure within their compression ratio limits.** Typically, in-line pipeline compressors have compression ratios of up to 2 to 1. By blocking the upstream valve of the targeted line segment while continuing to run the downstream compressor, the pipeline pressure can be reduced to approximately 50 percent of the working line pressure. The compressor can then be shut down and the line segment fully blocked. Lowering the line pressure by one-half is often sufficient to safely install sleeves over damaged line. This type of line pump-down process should be done only in a manner consistent with safety management policies.

- ★ **Using a portable compressor to further lower the line pressure.** Operators can also consider using portable compressors to achieve additional reduction beyond what in-line compressors can provide. Portable compressors can have up to a 5 to 1 compression ratio. When used in combination with an in-line compressor, portable compressors can lower line pressure by up to 90 percent of its original value without venting. Portable compressors can be used safely only when the downstream block valve is sufficiently manifolded. Again, safety policies should be strictly followed when using a portable compressor.

Although a portable compressor can recover an additional 40 percent of the original pipeline gas for sale, it is most appropriately used during planned maintenance, such as Class 1 and 2 repairs. This is because of the difficulty of renting or leasing a unit, mobilizing it, and depressurizing the line in a timely and cost-effective manner during an emergency. Portable compressors also are more easily justified when multiple sections of pipeline are taken out of service, either as a single project or as a set of serial repairs.

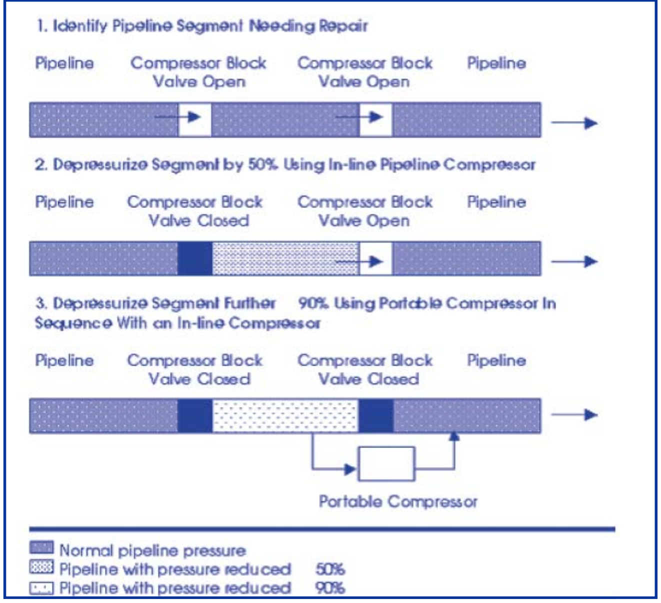
Exhibit 1 summarizes which pump-down techniques are applicable for the different classes of pipeline repair.

Exhibit 2 illustrates the basic sequence of events for depressurizing a pipeline segment.

Exhibit 1: Applicability of Pipeline Pump-Down Techniques

Repair Class	Pump-Down Technique	Description of Applicability
Class 1	In-line and Portable	These techniques can be used most extensively for Class 1 and Class 2 because such repairs primarily involve non-emergency situations and planned maintenance.
Class 2		
Class 3	In-line only	Class 3 typically involves emergency repairs with significant urgency to return the pipeline to service, leaving no time to mobilize a portable compressor.
Class 4	In-line only	Class 4 projects can be vast, with new pipe being run parallel to existing pipelines. Opportunities exist for recovering gas from the old lines during startup of the new line, but must be coordinated very carefully because of the size of the projects.

Exhibit 2: Sequence of Depressurization Events



Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance

(Cont'd)

Economic and Environmental Benefits

Companies can realize significant environmental and economic benefits by using downstream in-line and portable compressors to lower gas-line pressure before performing maintenance and repair activities. Potential savings include:

- ★ Recovery and sale of natural gas that would have been vented to the atmosphere. In the case of production pipelines, the gas stream might also contain valuable heavy hydrocarbons.
- ★ Reduction of methane emissions.
- ★ Reduction of nuisance odor and noise.
- ★ Elimination or significant reduction of hazardous air pollutant (HAP) emissions, primarily benzene, toluene, ethyl benzene, and xylene (BTEX).

Decision Process

When gas pipelines require maintenance or repair, companies can either:

- ★ Vent gas in the damaged section of pipeline to the atmosphere.
- ★ Recover as much of the pipeline gas as possible.

Step 1: Estimate the quantity and value of gas that in-line compressors can recover.

Depending on the compression ratio of the downstream in-line compressor(s), up to 50 percent of gas in the line can be recovered at minimal or no cost to the operator. Exhibit 3 provides calculations that operators can use to determine the total amount of gas in the pipeline segment and the amount and value of gas that can be recovered using the in-line compressor(s).

Step 2: Verify technical feasibility of using a portable compressor.

After calculating the potential volume of pipeline gas recoverable by an inline compressor, the operator should determine if the mechanical capability exists to use a portable compressor.

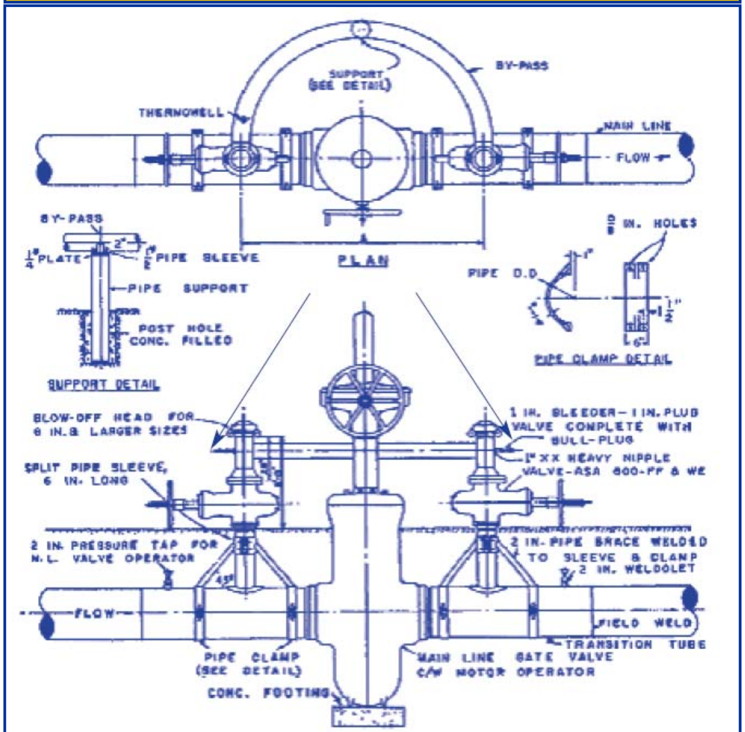
A portable compressor can further reduce the line pressure by moving up to 40 percent of the remaining original gas volume to the pressurized side of the block valve; however,

Exhibit 3: Gas Savings from Use of the In-line Compressor

Given:	
L I P Ri	= Pipeline length between block valves (miles) = Pipeline interior diameter (feet) = Pipeline operating pressure (psig) = In-line compressor compression ratio
(1)	**Calculate: M = Amount of Gas in Pipeline**
M	= L x (5,280 ft/mile) x π x (I / 2)^2 x (P +14.65 psig) / 14.65 psig
(2)	**Calculate: Ni = Gas recoverable using an in-line compressor**
Ni	= M - (M/Ri)
(3)	**Calculate: Vi = Value of gas recovered using an in-line compressor**
Vi	= Ni x $7/Mcf

using a portable compressor is only possible if the compressor can physically connect to the pipeline. Exhibit 4 illustrates a typical gas pipeline manifold. At a minimum, proper portable compressor connections should include bleeder valves upstream and downstream of a mainline block valve. The minimum size of bleeder valves

Exhibit 4: Gas Pipeline Block-valve Manifold System



Source: *Gas Engineers Handbook*

depends on the size of the portable compressor. A technical representative from the portable compressor leasing or manufacturing company can specify manifolding requirements for specific units.

Step 3: Determine the appropriate-sized portable compressor for the project.

Selecting an appropriately sized portable compressor is best done with the assistance of a leasing company or manufacturer's technical representative who can recommend a portable compressor that satisfies the project requirements (e.g., amount of gas, discharge pressure requirements, schedule).

Step 4: Check the availability and cost of purchasing or leasing a portable compressor.

Companies considering a portable compressor are often faced with the question of whether to rent or purchase the unit. A limited number of portable gas compressors are available for rent, and rental companies typically prefer long-term leases. If the continual use of portable compressors for line pump-down activities is planned, companies might want to consider purchasing a portable gas compressor. Even then, availability and internal cost remain important considerations. Exhibit 5 shows the wide cost ranges for several operating scenarios.

★ **Other purchasing considerations.** In addition to the purchase price, other capital expenditures include taxes and administrative costs, installation costs, and freight costs. Installation costs are often site specific. One vendor indicated these costs could be as low as $3,886 or as high as $19,430 for a small compressor (i.e., less than 100 horsepower), and can range from $19,430 to $77,718 for a large unit (i.e., more than 2,000 horsepower). Freight costs are also site-specific, ranging from $7,900 to $13,170 for small units and $26,300 to $39,500 for larger units. All these cost factors should be included in the total purchase price of the compressor and when calculating the annualized cost of a compressor. Vendors indicated the lifetime of compressor units ranged between 15 to 20 years if properly maintained.

★ **Other leasing considerations.** Leased compressors also have similar installation and freight costs. Leasing prices are usually on a monthly basis. One vendor indicated that monthly rental expenses were approximately 3 percent of the purchase price. Another vendor provided a rental price based on the horsepower of the compressor. These rental prices ranged from $15 per horsepower per month for large compressors to $20 per horsepower per month for small compressors.

Exhibit 5: Portable Compressor Purchase and Lease Cost Range*

1,000 PSIG - High Flow		600 PSIG - Medium Flow		300 PSIG - Low Flow	
Purchase	Lease	Purchase	Lease	Purchase	Lease
$3 - $6 million	$77,000 - $194,000 per month	$1.0 - $1.6 million	$31,000 - $46,000 per month	$518,131 - $777,197	$15,000 - $23,000 per month

* Based on assumptions that purchase cost does not include cost of freight or installation and that lease cost is 3 percent of purchase cost.

Maximizing the benefits of this investment requires coordinating planned maintenance activities to lower the compressor's mobilization or demobilization costs. Such coordination is especially important for maintenance conducted on smaller, lower pressure gas lines because margins diminish as the volume of potentially recoverable gas is reduced.

Step 5: Estimate the operating costs associated with using a portable compressor.

Operating costs include fuel/energy, maintenance, and labor costs. Natural gas is the fuel most frequently used to operate compressors. Vendors indicated that fuel usage ranged from 7,000 to 8,400 Btu per brake horsepower per hour. Maintenance costs range from $5 to $12 per horsepower per month depending on the compressor's size.

Seven Steps to Evaluate the Use of In-line and Portable Compressors:

- Step 1: Estimate the quantity and value of gas that in-line compressors can recover.
- Step 2: Verify technical feasibility of using a portable compressor.
- Step 3: Determine the appropriate-sized portable compressor for the project.
- Step 4: Check the availability and cost of purchasing or leasing a portable compressor.
- Step 5: Estimate the operating costs associated with using a portable compressor.
- Step 6: Calculate the volume and value of the gas recovered by a portable compressor.
- Step 7: Evaluate the economics of using a portable compressor in sequence with an in-line compressor.

In most cases, however, the maintenance costs are included in the rental price.

Step 6: Calculate the volume and value of the gas recovered by a portable compressor.

The gas available for recovery using the portable compressor is a function of the amount of gas remaining in the pipeline section being repaired. Since the in-line compressor already has reduced the gas volume, the portable compressor works with the reduced volume.

The recovery of gas is governed by the compression ratio. The volume of portable compressor-recovered gas is equal to the volume of gas in place minus the volume of gas divided by the compression ratio. The gross value of the recoverable gas using the portable compressor is the amount of gas in Mcf multiplied by the gas price in $/Mcf. These calculations are shown in Exhibit 6.

Exhibit 6: Calculating Gas Savings from Using a Portable Compressor

Given:	
M Ni Rp Vi	= Gas originally available for recovery (Mcf) = Gas recovered using an in-line compressor (Mcf) = Portable compressor compression ratio = Value of gas recovered from in-line compressor ($)
(1)	**Calculate: Np = Gas recovered using a portable compressor**
Np	= Ni - (Ni/Rp)
(2)	**Calculate: Vg = Value of gas recovered using a portable compressor**
Vg	= Np x $7/Mcf

Step 7: Evaluate the economics of using a portable compressor in sequence with an in-line compressor.

The net value of recovering gas from the pipeline section being repaired can be determined by subtracting the cost (i.e., operating costs, leasing costs, or annualized costs) from the value of gas recovered using the unit. Operators can effectively reduce the cost of using a portable compressor by planning and executing multiple projects in succession. The total value of gas recovered by the in-line compressor and the portable compressor is the sum of the two valuations. The total economic evaluation includes subtracting the costs of this procedure. Exhibit 7 shows this valuation procedure.

Exhibit 7: Calculating Total Economic Benefit of Using a Portable Compressor in Sequence with an In-line Compressor

Given:	
Vi Vg Vcf Vcl Vcm Vci Vcs Vcp Vct CR I N	= Value of gas recovered using in-line compressor ($) = Value of gas recovered using a portable compressor ($) = Cost of fuel, see Step 5 = Cost of labor = Cost of maintenance, see Step 5 = Capital cost of installation, see Step 4 = Capital cost of freight, see Step 4 = Purchase cost of compressor, see Step 4 = Cost of taxes and administration = Capital recovery factor (Where CR = $[I \times (1+I)^n] / [(1+I)^n-1]$) = Interest rate = Number of years in contract period (rental) or lifetime (purchase)
(1)	**Calculate: Vcr = Cost of capital investment recovered over the duration of the compressor contract period**
Vcr	= (Vci + Vcs + Vcp + Vct) x CR
(2)	**Calculate: Vc = Total costs associated with a portable compressor**
Vc	= Vcf + Vcl + Vcm +Vcr
(3)	**Calculate: Vp = Net value of recovered portable gas**
Vp Vp Vp	= Net value of portable recovered gas = Value of portable recovered gas - operating cost ($) = Vg - Vc
(4)	**Calculate: Vt = Total value of recovered gas**
Vt Vt Vt	= Total value of in-line and portable recovered gas = Total value of in-line recovered gas + net value of portable recovered gas = Vi + Vp

Sample Gas Recovery Scenario

Sample Scenario Using Portable Compressor

A company's 30-inch exterior diameter (28.5-inch interior diameter) pipeline operating at 600 pounds per square inch (psig) requires a blow down prior to maintenance at various 10 mile stretches. The downstream in-line reciprocating compressors have a compression ratio of 2 to 1 and can be safely used to draw down line pressure. A leased portable compressor with an effective 8 to 1 compression ratio operating at 1,000 horsepower is available at $31,000 per month (including maintenance costs) and can be manifolded to one of the block-valve systems. The portable compressor can remove approximately 416 Mcf per hour and consumes 7,000 Btu per horsepower per hour. The maintenance crew can

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

install and operate the compressor at no additional cost to the company. Freight costs to transport the portable compressor from the rental company to the user total \$19,000. The blowdown and maintenance will be done an average of 4 times per month. The portable compressor will be leased for a 12-month period.

To determine the benefits associated with using the portable compressor in combination with the in-line compressor, an operator used the following steps to calculate the net value of the recoverable gas. First, the operator calculated the total amount of gas available for recovery.

Exhibit 8: Total Volume of Gas Available for Recovery

Total gas available for recovery for each 10 mile stretch:

= 10 miles x 5,280 feet per mile x (π x (2.375 feet)^2 ÷ 4) x ((600 psig + 14.65) ÷ 14.65 psig) x 1 Mcf per 1,000 cf

Then the operator calculated the volume and value of gas recoverable using the in-line compressor.

Exhibit 9: Net Savings Associated with Using the In-line Compressor

Amount of gas recoverable per action using the in-line compressor:

= 9,814 Mcf - (9,814 Mcf ÷ 2.0 in-line compression ratio)
= 4,907 Mcf recovered per action using in-line compression

Value of gas recovered per action using the in-line compressor:

= 4,907 Mcf x \$7.00 per Mcf
= \$34,349 per action

Annual value of gas recovered assuming 4 actions per month:

= \$34,349 x 4 per month x 12
= \$1,648,752

Next, the operator calculated the volume and gross value of gas recoverable using a portable compressor.

Exhibit 10: Gross Savings Associated with Using the Portable Compressor

Gas available to be recovered using the portable compressor:

= Total gas available - gas recovered by in-line compressor
= 9,814 Mcf - 4,907 Mcf
= 4,907 Mcf recoverable gas available for portable compressor

Gross value of the gas recoverable per pump-down using a portable compressor:

= gas recoverable using portable compressor x value of gas
= [4,907 Mcf - (4,907 Mcf ÷ 8 portable compression ratio)] x \$7.00 per Mcf
= \$30,056

Gross value of the recoverable gas during a 12-month period, assuming an average of 4 pump-downs per month:

= \$30,056 x 4 x 12
= \$1,442,688

The operator also needed to account for fuel, maintenance, and freight costs associated with the portable compressor.

Exhibit 11: Costs Associated with the Portable Compressor

To calculate the fuel costs, the operator first needed to determine how many hours the compressor would be operating and based on those hours, the amount of fuel used for each 10-mile stretch:

Hours the portable compressor will operate to remove the volume of gas:
= gas recoverable using portable compressor ÷ rate of compressor
= (4,907 Mcf - (4,907 Mcf ÷ 8 compressor ratio)) ÷ 416 Mcf per hour
= 10 hours

Fuel used, assuming natural gas has a heat content of 1,020 Btu/scf:
= 7,000 Btu/hp/hour x 1,000 hp x 10 hours ÷ 1,020 Btu/scf ÷ 1,000 scf/Mcf
= 69 Mcf for each 10-mile stretch

Fuel costs assuming four 10-mile stretches per month:
= \$7.00 per Mcf x 69 Mcf x 4
= \$1,932 per month

Lease and maintenance costs
= \$31,000 per month

Freight Cost
= \$19,000

Total cost of using the portable compressor during a 12-month period:
= fuel costs + lease and maintenance cost + freight costs
= 12 x (\$1,932 + \$31,000) + \$19,000 = \$414,184

Subtracting the portable compressor costs from the savings yields the net savings associated with using a portable compressor.

Adding net savings from the in-line and portable compressors yields the total net savings for this scenario.

Exhibit 12: Net Savings Associated with Using the Portable Compressor

Total net value of the recovered gas during a 12-month lease using the portable compressor:
= $1,442,688 - $414,184
= $1,028,504

Exhibit 13: Net Value of Savings from Entire Recovery Scenario

Net value of the recovered gas from the entire scenario (in-line + portable)
= $1,648,752 + $1,028,504
= $2,677,256

Lessons Learned

Using pump-down techniques to depressurize the pipeline during planned maintenance activities allows companies to economically recover 50 percent to 90 percent of the vented natural gas. Partners offer the following lessons learned when using in-line and portable compressors to recover pipeline contents:

★ Always perform in-line compressor pipeline pump-downs as part of a planned maintenance program. Even when portable compressors are not used, in-line compressors can reduce venting emissions.

★ Incorporate in-line compressor pump-downs into emergency procedures. Although it is more difficult to perform pipeline pump-downs during emergencies (e.g., repairing leaking pipelines) than during planned maintenance, emergency pump-downs still can generate substantial gas and cost savings.

★ Partners can maximize gas and cost savings by using portable compressors intensively, making repairs or upgrades on multiple segments of line taken out of service in turn. Check portable compressor availability and sizes when planning operations. Availability of portable compressors can be limited in isolated areas.

★ Manifold at least one of the two mainline block valves to accommodate portable compressors.

★ If possible, calculate the economics of recovering natural gas before planned maintenance activities. This ensures the cost-effectiveness of the activities.

★ Include reductions in methane emissions realized through this approach in Natural Gas STAR Program annual reports.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Case Study: One Partner's Experience

In 1998, Southern Natural Gas Company saved 32,550 Mcf using pump-down compressors to evacuate pipelines. The company used compressors at one location three times per year at an estimated total cost of $68,100 at 2006 costs. The company estimated saving nearly $228,000 in recovered product, using $7/Mcf as the value of gas no longer being vented. Subtracting pump-down costs from the value of gas saved, the company achieved net savings of $159,900. In this case, the estimated payback period for the portable compressor was approximately 4 months.

Case Study: One Partner's Experience

One Partner reported saving more than 8 MMcf during a 55-month period using an ejector installed on a pipeline bleeder. Typical methane emissions reductions can be estimated as 700 Mcf per year for one ejector installed to evacuate 2 miles of 18-inch out-of-service pipeline from 600 to 50 psig, using 200 feet of 1-inch piping connections, once per year.

This practice requires an adjacent operating pipeline with vent connections on both sides of a block valve or compressor, in close proximity to the pipeline being taken out of service and depressurized.

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United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

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PRO Fact Sheet No. 505

Partner Reported Opportunities (PROs) for Reducing Methane Emissions

Recover Gas from Pipeline Pigging Operations

Technology/Practice Overview

Description

Gases rich in recoverable hydrocarbons tend to condense liquids in gathering systems upstream of gas gathering and processing plants. These systems are frequently pigged with spherical or bullet-shaped pigs to remove accumulated liquids and reduce the gathering system pressure drop. This improves gas flow and pipeline efficiency. The pigged liquids are separated from the gas ahead of the processing plant compressors, stored temporarily at gathering system pressure, and then sent to a low pressure storage tank. The liquids, recovered at pipeline pressure, flash and vent light hydrocarbon gases from the storage tanks.

Much of the gas that is vented can be recovered by installing a dedicated vapor recovery system. Recovering the flash gas resulting from the pressure drop between the pressurized liquid storage tanks and the atmospheric storage tanks can reduce emissions and add more gas to the sales line.

Operating Requirements

The required equipment to be installed includes an electric or a gas engine driven vapor recovery compressor. A liquid/vapor flash vessel and low pressure liquid pump may also be required depending on system design and/or ambient temperature and pressure. It is assumed that a pig launcher and receiver on gathering lines, vapor/liquid separation and pressurized liquid storage vessels, and low pressure liquid storage tanks would already be

- □ Compressors/Engines
- □ Dehydrators
- □ Directed Inspection & Maintenance
- ■ Pipelines
- □ Pneumatics/Controls
- ■ Tanks
- □ Valves
- □ Wells
- □ Other

Applicable Sector(s)

- ■ Production
- ■ Processing
- ■ Transmission
- □ Distribution

Other Related PROs:

Use Inert Gases and Pigs to Perform Pipeline Purges, PRO No. 403

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*21,400 Mcf per year*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	21,400 Mcf	$159,400	$24,000	$1,000	2 Month
$5.00/Mcf	21,400 Mcf	$113,800	$24,000	$1,000	3 Month
$3.00/Mcf	21,400 Mcf	$68,300	$24,000	$1,000	5 Months

* *Whole gas savings are calculated using a conversion factor of 94% methane in pipeline quality natural gas.*

Additional Benefits

- Addition of gas to the sales line (or plant fuel system)
- Recovery of valuable hydrocarbon liquids
- Safer operations

Recover Gas from Pipeline Pigging Operations (Cont'd)

present on site. Vapor recovery compressor sizing is affected by the variance of pigging operations; colder temperatures in the winter can require extra capacity that is not necessary in the summer months. This is because colder temperatures result in more condensation at constant pressure. Pipelines would therefore have to be pigged more often. In general, gathering lines that must be pigged frequently and recover a large volume of liquid at moderate to high pressure (150 to 300 psig or greater) are best suited for vapor recovery.

Applicability

Gas and condensate recovery is possible at any gas gathering station and processing plant that frequently must remove condensed liquids from its upstream gathering lines.

Methane Emissions

The methane emission savings are based on the design flow rate and operating time of a single vapor recovery compressor dedicated to the compression of the flash vapor from the pigged liquid (pressurized) storage tanks.

Economic Analysis

Basis for Costs and Emissions Savings

For example reported savings are based on a gathering system at 200-300 psig (pounds per square-inch, gage) that is pigged 30-40 times per year and collects approximately 3,000 barrels of condensate per year. A small vapor recovery system was installed with an electric compressor for $24,000 and has an annual operating and maintenance cost in excess of $1,000 per year.

Discussion

Gathering system pigging frequency depends on the gas composition as well as the ambient temperature conditions, and can vary greatly from one location to another and from season to season. The economics of recovering gas from pigging operations are dependent upon the methane through butane composition of the hydrocarbon liquid, which directly impact the energy content and value of the gas, and the amount of liquid collected.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.