U.S. DEPARTMENT OF ENERGY

Office of Oil and Natural Gas
Office of Fossil Energy

NATURAL GAS FLARING AND VENTING: STATE AND FEDERAL REGULATORY OVERVIEW, TRENDS, AND IMPACTS

June 2019

EXECUTIVE SUMMARY

The purpose of this report by the Office of Fossil Energy (FE) of the U.S. Department of Energy (DOE) is to inform the states and other stakeholders on natural gas flaring and venting regulations, the level and types of restrictions and permissions, and potential options available to economically capture and utilize natural gas, if the economics warrant. While it is unlikely that the flaring and limited venting of natural gas during production and handling can ever be entirely eliminated, both industry and regulators agree that there is value in developing and applying technologies and practices to economically recover and limit both practices. FE's objective is to accelerate the development of modular conversion technologies that, when coupled with the currently available commercial alternatives, will provide a complete portfolio of options for companies seeking to monetize flared gas volumes of practically any magnitude and at any location.

Natural gas is a gaseous mixture of hydrocarbon compounds, the primary one being methane and non-hydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen). Natural gas flaring is the controlled combustion of volatile hydrocarbons and venting is the direct release of natural gas into the atmosphere, typically in small amounts. While flaring is more common than venting, both of these activities routinely occur during oil and natural gas development as part of drilling, production, gathering, processing, and transportation operations. The reasons behind both flaring and venting may be related to safety, economics, operational expediency, or a combination of all three. Both federal and individual state regulations control the amount of flaring and venting that is permitted, as described in the "Analysis of State Policies and Regulations" section of this report.

Domestically, flaring has become more of an issue with the rapid development of unconventional, tight oil and gas resources over the past two decades, beginning with shale gas. Unconventional development has brought online hydrocarbon resources that vary in their characteristics and proportions of natural gas, natural gas liquids and crude oil. While each producing region flares gas for various reasons, the lack of a direct market access for the gas is the most prevalent reason for ongoing flaring. Economics can dictate that the more valuable oil be produced and the associated gas burned (or reinjected) to facilitate that production. Until transmission, storage, and delivery infrastructure increases in these newer or expanding producing regions, flaring and venting will continue to represent environmental issues and lost market opportunities. Of specific importance has been the increase in flaring of gas associated with oil production in liquids rich plays where there is not enough gas gathering and transportation infrastructure to enable the gas to be marketed.

Two states where flaring has increased are Texas and North Dakota, while both states are working with producers to limit the need for flaring without shutting down or impacting the timely and continued production of oil from new wells. In both cases, these states have seen rapid development of unconventional oil plays (e.g., Permian Basin and Eagle Ford in Texas and Bakken Shale in North Dakota) with significant volumes of associated gas production. In 2017, the volumes of gas flared and vented reported to DOE's

Energy Information Administration (EIA) by Texas totaled 101 billion cubic feet (Bcf) and North Dakota by 88.5 Bcf. These totals are 10 to 20 times the volumes reported by other states that collect such data and the numbers reflect the much higher level of oil and natural gas production in these two states.

Data on flaring and venting volumes have been collected from producers by some producing state agencies, who then share the data with EIA. The data compiled by EIA show that the reported volumes of gas flared reached levels of between 225 and 285 Bcf per year in the mid-1990s. After dropping to less than half that during the early 2000s, reported flared volumes have again risen to levels between about 200 and about 300 Bcf per year during the 2011-2017 time period as both oil and natural gas production levels have increased significantly.

Every oil- and gas-producing state has in place regulations to limit or prevent the "waste" of gas resources. However, the flaring limits vary from state to state and no national standards currently exists. FE has developed a series of individual state fact sheets that summarize the flaring and venting regulations applicable in each of 32 oil- and gas-producing states and provide context and contact information for interested stakeholders. These fact sheets will be available on FE's website.

In the states where a large number of associated gas flares have been permitted over the past few years, planned increases in natural gas processing and pipeline takeaway capacity may reduce the volume of flaring over the next five years. In both Texas and North Dakota, gas processing and gas pipeline capacities are being expanded to handle the increased volumes of associated gas being produced so that it can be economically captured and sold. In the short term, however, flaring percentages have the potential to rise above current levels in both Texas and North Dakota if oil prices continue to recover and drilling rigs remain active.

Many companies have implemented technology solutions to venting—voluntarily or in response to regulations, although continued increases represent losses to valuable economic resources and sources for emissions. Technologies currently exist to capture gas that would otherwise be flared and convert it into useful products, or used onsite to facilitate production. Opportunities exist to increase the prevalence of these technological solutions and improve their economical uses, ultimately benefiting domestic and international gas consumers.

Commercial alternatives to flaring include compressing natural gas and trucking it short distances for use as a fuel for oil field activities; extracting natural gas liquids from the flare gas stream before flaring the remaining methane (a partial solution); converting the gas to electric power using small-scale generators, small-scale gas-to-methanol or gas-to-liquids conversion plants; and converting captured gas to LNG and trucking it short distances for use as a fuel for oil field activities.

FE is currently implementing a plan to expand its research program focused on mitigating emissions from midstream natural gas infrastructure. One of the areas of interest is focused on accelerating the development of technologies capable of converting gas that would otherwise be flared, into transportable, value-added products. It is envisioned that successful technologies developed in this research and development effort will be integrated into small-scale modular systems that, in the future, can be transported from one flare site to the next for use during periods when planned natural gas gathering and transportation systems are not yet functional.

FE is specifically targeting two areas where basic research needs have been identified: (1) multifunctional catalysts, and (2) modular conversion equipment designs. The first area involves the early-stage development and evaluation of multifunctional catalysts for the direct conversion of methane to liquid petrochemicals (e.g., methanol, ethanol, ethylene glycol, acetic acid, and other hydrocarbons) that can be easily transported and are suitable for subsequent conversion into commercial products. The second area of interest is the development of novel equipment and process design concepts for achieving high-selectivity pyrolysis, which is integral to the manufacture of high-value carbon products from methane or the mixtures of methane, ethane, propane, and butanes representative. Research in this area will focus on the application of process intensification at modular-equipment scales suitable for deployment and transport between remote locations where gas is being flared.

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INTRODUCTION TO NATURAL GAS FLARING AND VENTING

FLARING AND VENTING DEFINITIONS

Natural gas flaring is defined as the controlled combustion of natural gas for operational, safety, or economic reasons. Venting is the direct release of natural gas into the atmosphere. Categories of natural gas flaring and venting in the upstream oil and natural gas industry include the following:

1. **Flaring for Operational and Safety Reasons**
    - Diversion and disposal of gas influx (kick) during drilling.
    - Diversion and disposal of produced gas during well testing (Figure 1).
    - Diversion and disposal of flowback gas during the well completion process.
    - Disposal of natural gas diverted from oil and gas compression or processing equipment due to maintenance operations, system upset condition, or pressure release emergency (Figure 2).
    - Disposal of relatively small volumes of waste gas from the routine operation of equipment utilized at an oil or gas processing facility.
2. **Flaring for Economic Reasons** (Figure 3 and Figure 4)
    - Associated gas produced with crude oil (also called casinghead gas) that has a ready market, but where the gathering, compression, and sales infrastructure for the gas is under construction but not yet operable, and where economic factors require early oil production in advance of natural gas capture.
    - Associated gas produced with crude oil that has a ready market, but where construction and installation of a gathering, compression, and sales infrastructure for the gas is not economic, or where the required expansion of the existing system is not economic.
3. **Venting for Operational Reasons**
    - Venting of natural gas diverted from oil and gas compression or processing equipment due to system upset condition or pressure release emergency.
    - Blow-down of gas from processing equipment, pipelines or compressors prior to repairs.
    - Bleed-off of gas pressure during routine operation of pneumatic devices (e.g., motor valve controllers, pressure and level controllers) (Figure 5).
    - Routine emissions from natural gas driven pneumatic pumps.
    - Venting to avoid pressure buildup in crude oil, condensate (light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. Mostly pentanes and heavier hydrocarbons. Normally enters the crude oil stream after production.), or water storage tanks operating without vapor recovery systems (Figure 6).
    - Leakage from compressor seals (both reciprocating and centrifugal compressors).

- Fugitive emissions from equipment leaks (e.g., stuck dump valves, storage tank hatches left open, cracked flange seals).
- Routine emissions from glycol dehydrator still columns and flash tanks, and amine natural gas sweetening units (Figure 7).
- Emissions during oil or condensate loading/unloading at tank truck or barge transport facilities.
- Routine well venting during liquids unloading on low-pressure gas wells.

FIGURE 1. Photograph of the gas flare from the thermal gas hydrate production test in the Mallik 5L-38 Gas Hydrate Research Well. *Photo with permission from S. R. Dallimore, Geological Survey of Canada.* (Source)[1]

FIGURE 2. Natural gas being flared at the Hess Corporation gas plant in Tioga, North Dakota, due to maintenance issues. *Photo credit Amy Dalrymple / Forum News Service* (Source)[2]

[1] https://www.researchgate.net/figure/Photograph-of-the-gas-flare-from-the-thermal-gas-hydrate-production-test-in-the-Mallik_fig3_29735752
[2] https://www.thedickinsonpress.com/business/energy-and-mining/3885727-gas-plant-repairs-will-add-flaring

FIGURE 3. Flares burning associated gas at a well in the Bakken shale oil field, North Dakota. *Photo courtesy of Joshua Doubek.* (Source)[3]

FIGURE 4. Permanent casinghead gas flare on a producing stripper oil well in Hopkins County, Kentucky. *Photo courtesy of Marvin Combs, Kentucky Division of Oil & Gas* (Source)[4]

[3] https://commons.wikimedia.org/wiki/File:Bakken_Flaring_Gas_at_night.JPG

[4] http://thepttc.org/workshops/eastern_091614/eastern_091614_Combs.pdf

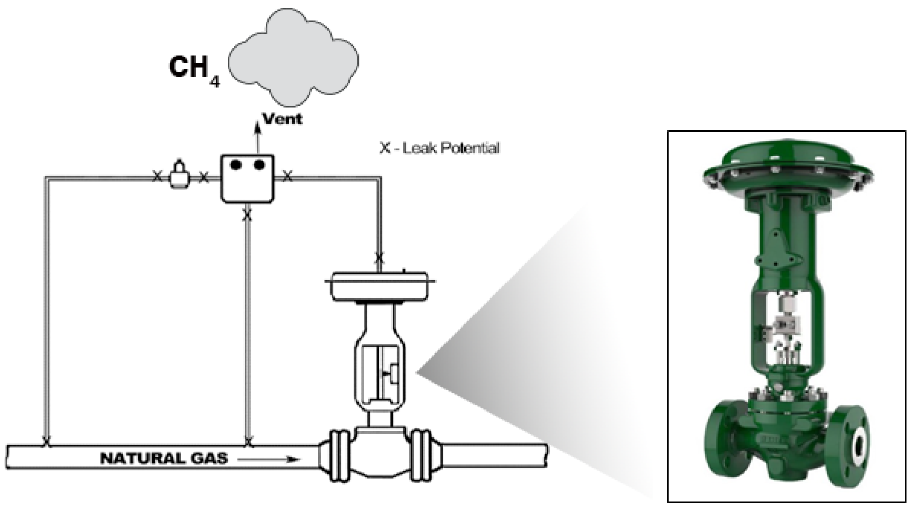


FIGURE 5. Schematic of a typical pneumatic controller actuated valve that operates off of gas pressure and routinely vents small volumes of natural gas to the atmosphere. In addition to the venting, poor maintenance can also lead to increased leak potential at the various connections that are needed to integrate the control system with the valve actuator. *Valve image courtesy of Emerson Automation Solutions and Fisher Controls International, LLC.* (Sources: 1 and 2) [5, 6]

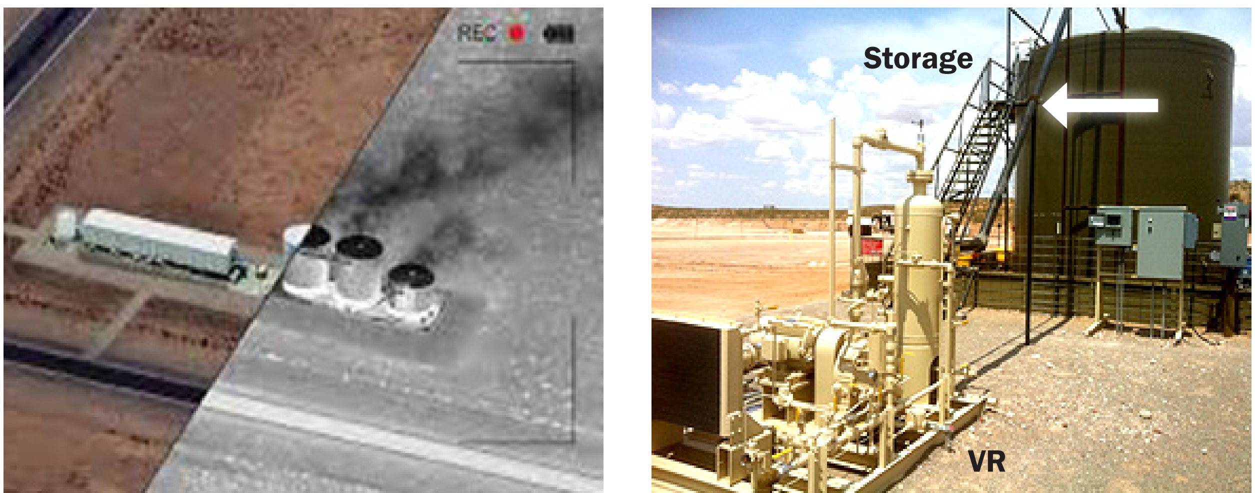


FIGURE 6. Aerial infrared photo showing crude oil tank vent emissions (left) and photo of vapor recovery (VR) unit installed on storage tank to prevent emissions (right, with connection line identified). *Photo courtesy of HY-BON/EDI* (Source)[7]

[5] https://www.epa.gov/sites/production/files/2016-04/documents/18boynton.pdf

[6] https://www.emerson.com/en-au/catalog/fisher-ew-en-au

[7] https://www.epa.gov/sites/production/files/2016-04/documents/8voorhis.pdf

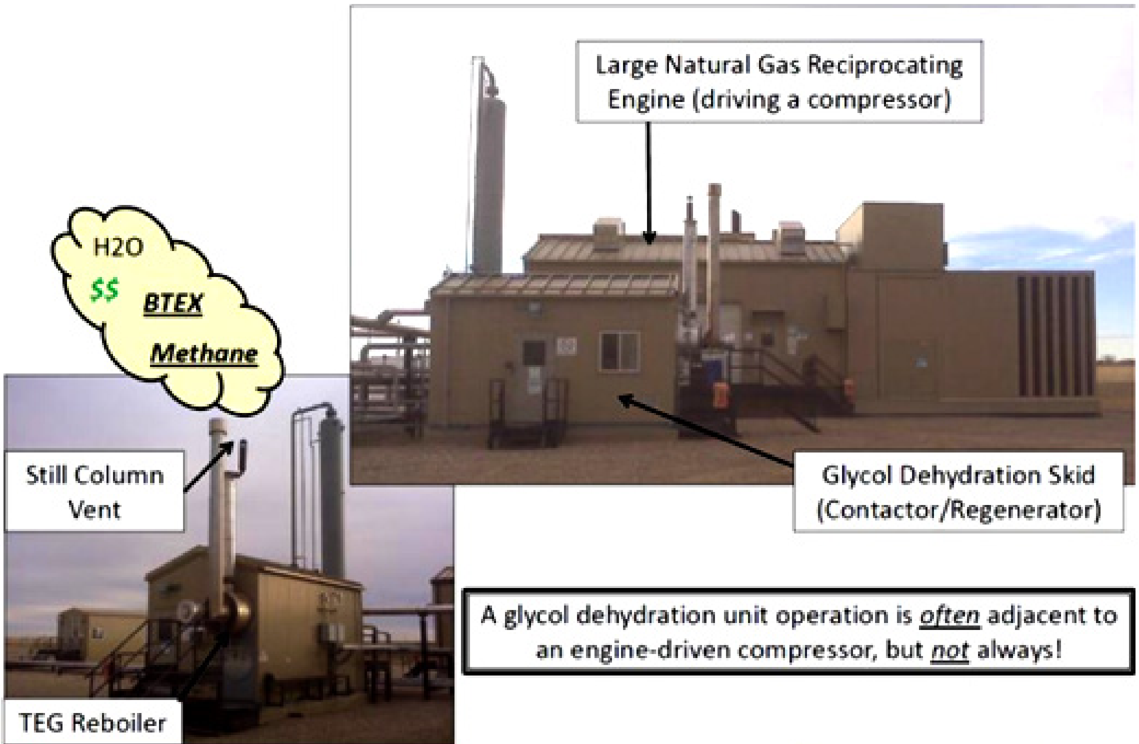


FIGURE 7. Photo of a tri-ethylene glycol dehydrator associated with a natural gas compressor station with still column vent identified. *Images with permission from Sean Hiebert.* (Source)[8]

The flaring that occurs for reasons listed in Category 1 above (i.e., Flaring for Operational and Safety Reasons) is generally short term and necessary to ensure safe operating practices. The venting that occurs in Category 3 (i.e., Venting for Operational Reasons) is generally low volume (or else it would be captured and flared under Category 1 as a safety hazard) and is often also required for safety reasons. Some venting is avoidable and could be reduced or prevented through the use of technology (e.g., by installing low-bleed controllers, vapor recovery units, improved compressor seals) or the application of better maintenance and best practices programs. In some cases, these options are economic and may result in the increase in gas sales volumes. In other cases, the required capital investment makes them uneconomic or marginally economic, and they will not be implemented unless required by regulations or corporate objectives determine them to be otherwise worthwhile. Category 2, the flaring of relatively large volumes of gas associated with oil production, either temporarily or long term, is the area that has generated the most concern among stakeholders and is a primary focus of this report.

Flaring of associated gas for extended periods of time may be necessary, with permission, if a well is being drilled in a new area that lacks natural gas pipelines. Several wells may be drilled and produced for an extended period of time before a company determines from the test data that an investment in production facilities and pipelines will meet economic standards. When the wells primarily produce oil or condensate, flaring of associated gas

[8] https://www.spartancontrols.com/-/media/library/engine-and-compressor-automation/rem-technology/waste-to-wealth_conocophillips-case-study.pdf?la=en

may continue even after the decision to continue with development and construct oil transport pipelines and facilities has been approved.

Eventually, when long-term volumes, pressures, and rates of associated gas production prove to be sustainable at levels that can economically justify installation of new gas gathering infrastructure or expansion of existing infrastructure, those investments will be approved, and the flaring will stop. If the economics cannot justify the investment, associated gas flaring may continue as long as it is not prohibited by state or federal regulations.

The economics of flaring versus capture and sales of associated gas are not necessarily a simple calculation. In addition to the expected volumes of gas to be recovered and the cost of the gathering lines and compression equipment needed, there are a number of other factors that must be considered. These can include the following:

- Producer's cost of capital
- Competition for investment dollars with other options in the producer's portfolio
- Proximity of intrastate and interstate pipelines and their capacities
- Natural gas prices and price risk
- Additional operating costs associated with natural gas production
- Lease terms
- Gas processing costs, which may be a function of gas composition
- Likelihood of right-of-way approvals
- Cost of land acquisition
- Likelihood of legal challenges and concerns regarding "social license to operate"
- Current flaring regulations and the likelihood of changes in the future.

Through the practice of flaring, methane is oxidized (through combustion) to carbon dioxide (CO_2) and water. From an environmental standpoint, flaring is better than venting since CO_2 is 25 times less impactful as a greenhouse gas than methane over a 100-year timespan.[9] However, depending on the constituents of the gas being flared (e.g., combustion of gas containing hydrogen sulfide produces sulfur dioxide emissions) and the efficiency of the flare equipment (e.g., some methane may escape unburned), there is no net negative impact from flaring versus sales in terms of environmental impact, assuming the flared gas, if captured, would be sold and then burned elsewhere under the same conditions.

Thirty-two states produce significant volumes of oil and natural gas and in every one of these states the venting and flaring of natural gas is regulated by state law. The state body charged with ensuring that state laws in this area are followed is typically a state's department of natural resources, oil and natural gas commission, state environmental protection agency or air quality board.

FLARING AND VENTING VOLUME ESTIMATES

EPA GHG Inventory – The U.S. Environmental Protection Agency (EPA) develops an annual report, called the *Inventory of U.S. Greenhouse Gas Emissions and Sinks (Inventory)*, that tracks and estimates U.S. greenhouse gas emissions by source going back to 1990. The report for 2019 was published in April 2019.[10] The relevant data for estimated methane emissions and CO_2 emissions related to upstream oil and natural gas operations are gathered in Table 1 and Table 2 below (green indicates oil production related equipment, yellow indicates gas, and light brown indicates equipment for both oil and gas).
The largest contributors are highlighted in red.

[9] EPA, 2019, https://www.epa.gov/ghgemissions/overview-greenhouse-gases

[10] EPA, 2019, Inventory of U.S. Greenhouse Gas Emissions and Sinks

Table 1 shows that about 350 billion cubic feet (Bcf) of methane is estimated to have been emitted each year over the 2015–2017 timeframe. The volumes of CO_2 estimated to have been generated by combustion or venting from oil and gas production and transportation processes are shown in Table 2.

EPA's inventory also identifies the largest contributors. In the case of methane emissions, it is pneumatic controllers and gas compressors.

In the case of flare-generated CO_2 emissions, it is associated gas flaring and acid gas treatment related flares, followed by oil storage tank vent flares and gas processing facility flares. Because the volumes of gas released during most gas venting and flaring activities are not measured, the EPA greenhouse gas inventory relies on a complicated process of data collection that utilizes surrogate indicators (e.g., number of wells completed, number of compressors) and emissions factor multipliers to arrive at their estimates.

TABLE 1. EPA Greenhouse Gas Inventory for Methane Emissions from Oil and Gas Operations

Source	2013	2015	2016	2017	% of Total (2017)
Natural gas compressor stations emissions	1,902	2,163	2,143	2,219	41%
Pneumatic controllers at oil and gas producing locations	1,918	1,862	1,882	1,894	35%
Venting from abandoned oil and gas wells	282	285	289	277	5%
Natural gas engines at gas processing facilities	228	234	250	256	5%
Natural gas transmission pipeline blowdowns	217	216	215	215	4%
Natural gas gathering pipeline leaks	139	137	137	142	3%
Liquids unloading from stripper gas wells	234	161	131	117	2%
Natural gas engines at gas producing facilities	131	125	118	114	2%
Chemical injection pumps	84	86	83	82	1%
Oil storage tank vent emissions	53	68	102	61	1%
Natural gas well workovers	73	13	16	34	1%
Oil well production heaters	23	29	27	28	1%
Natural gas gathering pipeline blowdowns	15	15	15	20	0%
Hydraulically fractured oil well completions	243	74	15	13	0%
Oil well workovers	24	13	6	2	0%
Total (Thousand Tons CH_4)	**5,566**	**5,481**	**5,429**	**5,474**	100%
Total (Billion Cubic Feet CH_4)	**354.5**	**349.1**	**345.8**	**348.7**	
Total (Thousand Tons CO_2 Equivalent)	**139,150**	**137,025**	**135,725**	**136,850**	

TABLE 2. EPA Greenhouse Gas Inventory for CO_2 Emissions from Oil and Gas Operations

Source	2013	2015	2016	2017	% of Total (2017)
Acid gas removal equipment flares	14,565	14,946	16,481	16,728	38%
Associated gas from oil production flares	10,384	13,955	8,587	10,506	24%
Natural gas processing facility flares	5,902	6,058	5,203	5,683	13%
Oil storage tank vent flares	5,937	7,598	5,894	4,422	10%
Miscellaneous flaring associated with oil production	2,606	3,571	2,201	2,631	6%
Hydraulically fractured oil well completions	2,214	1,913	1,162	1,619	4%
Misc. natural gas production flares	978	1,318	1,187	1,090	2%
Natural gas well storage tank flares	1,173	1,240	1,129	585	1%
Hydraulically fractured well flares	1,265	277	177	474	1%
Natural gas well workover flares	133	77	59	356	1%
Oil well workover flares	136	192	207	258	1%
Total (Thousand Tons)	**45,293**	**51,145**	**42,287**	**44,352**	100%

A map of EPA methane emissions estimates provides a good overview of the areas of the country where methane emissions are more likely (Figure 8). The high emissions areas align with oil and gas producing areas as would be expected. Some of the emissions estimates highlight metropolitan areas where natural gas distribution systems can leak methane. These can be seen to be more of an issue in eastern cities where older legacy systems are more prone to such emissions.

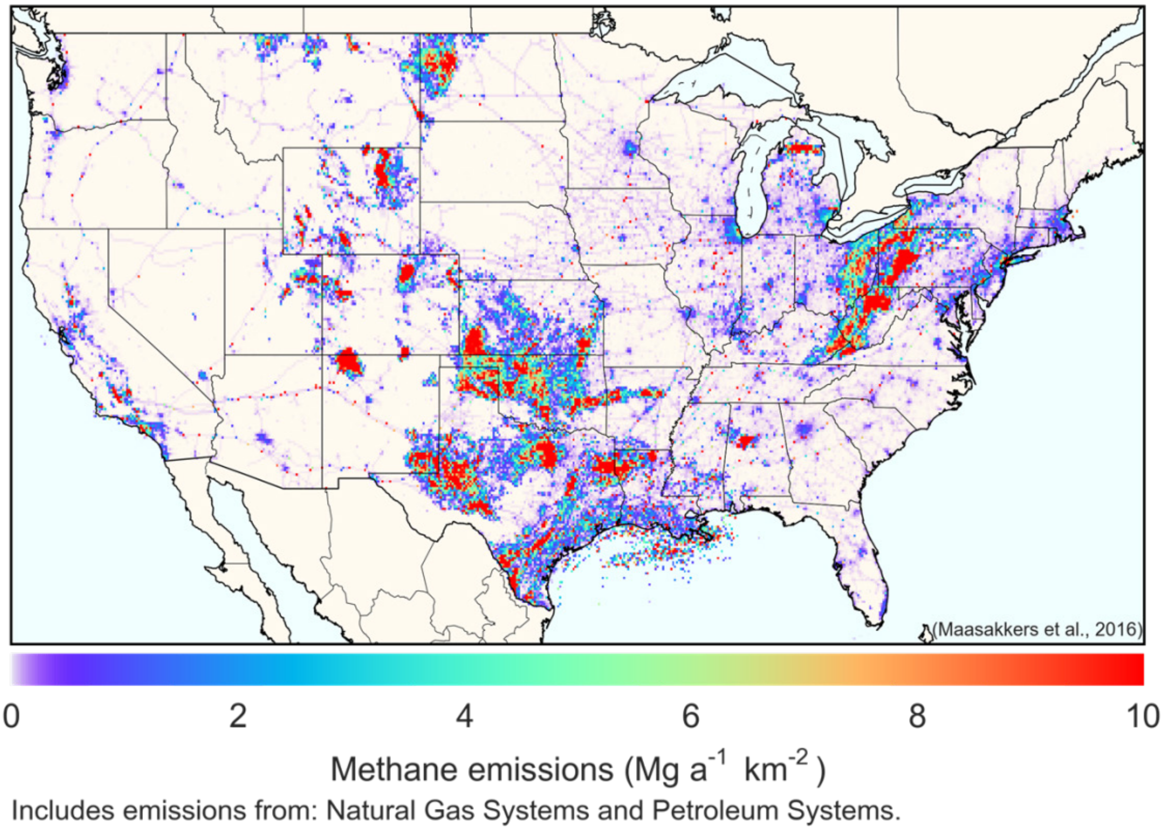


FIGURE 8. EPA greenhouse gas inventory distribution of methane emissions from the oil and natural gas sector (2012 data). (Source)[11]

Flaring Data Collected by DOE – Some U.S. natural flaring and venting data has been collected from producers by state agencies, who then share it with DOE's Energy Information Administration. EIA, in turn, aggregates and publishes the information on an annual basis (after a 9-month delay). The EIA-compiled flaring and venting data relies upon summary reports from states, which rely upon self-reporting by producers. Not all states collect flaring and venting data for submission to EIA, and those that do report do not necessarily follow the same reporting standards. The EIA data is available online and shown graphically in Figure 9. *(Note: Subsequent sections of this report will provide greater detail on the EIA data on a state-by-state basis).*

[11] https://www.epa.gov/sites/production/files/2016-11/gch4-oilgas.png

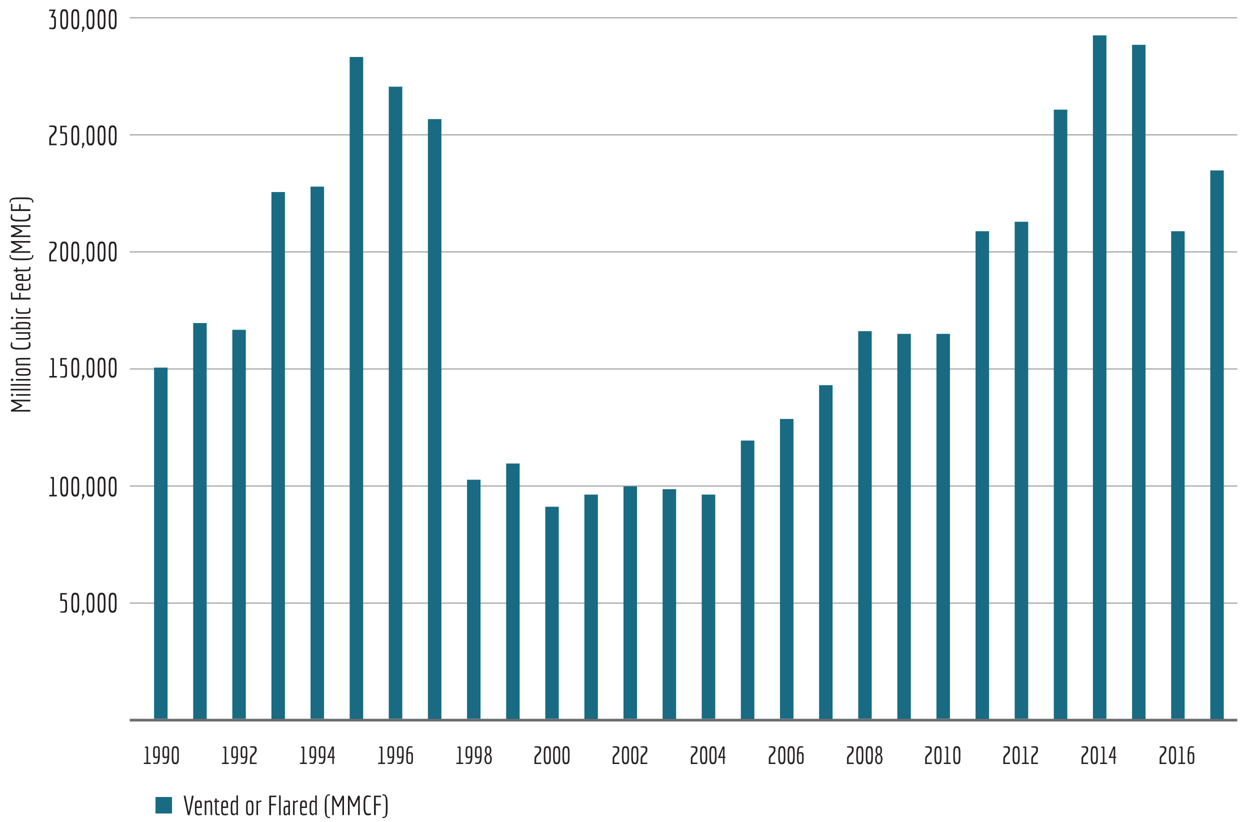


FIGURE 9. EIA venting and flaring data from 1990 thru 2017 (recent data from only 10 states, in some cases only for selected years). (Data Source: EIA)[12]

Satellite Image Estimation of Flared Volumes of Natural Gas – A potentially more accurate option for making an assessment of the number of flares and their size is through the use of sophisticated satellite systems. Entities such as the National Oceanic and Atmospheric Administration (NOAA) operate satellites that incorporate earth surveillance systems that can offer real-time data collection across the United States. NOAA began to monitor global flaring by satellite a few years ago. The organization applies sophisticated processing systems to observe and analyze flaring signals. The data generated from observations of shortwave and near-infrared emissions at night is collected, processed, and archived through a system known as the Visible Infrared Imaging Radiometer (VIIR) Suite (Figure 10). NOAA researchers have constructed a data processing algorithm that determines the quantity of gas combusted during flaring from point sources. Data identified as non-flaring-related (e.g., forest fires and city lights) are disregarded. NOAA assessed the results as accurate to within plus or minus 9.5% of the actual flared gas volume.

[12] https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_a.htm

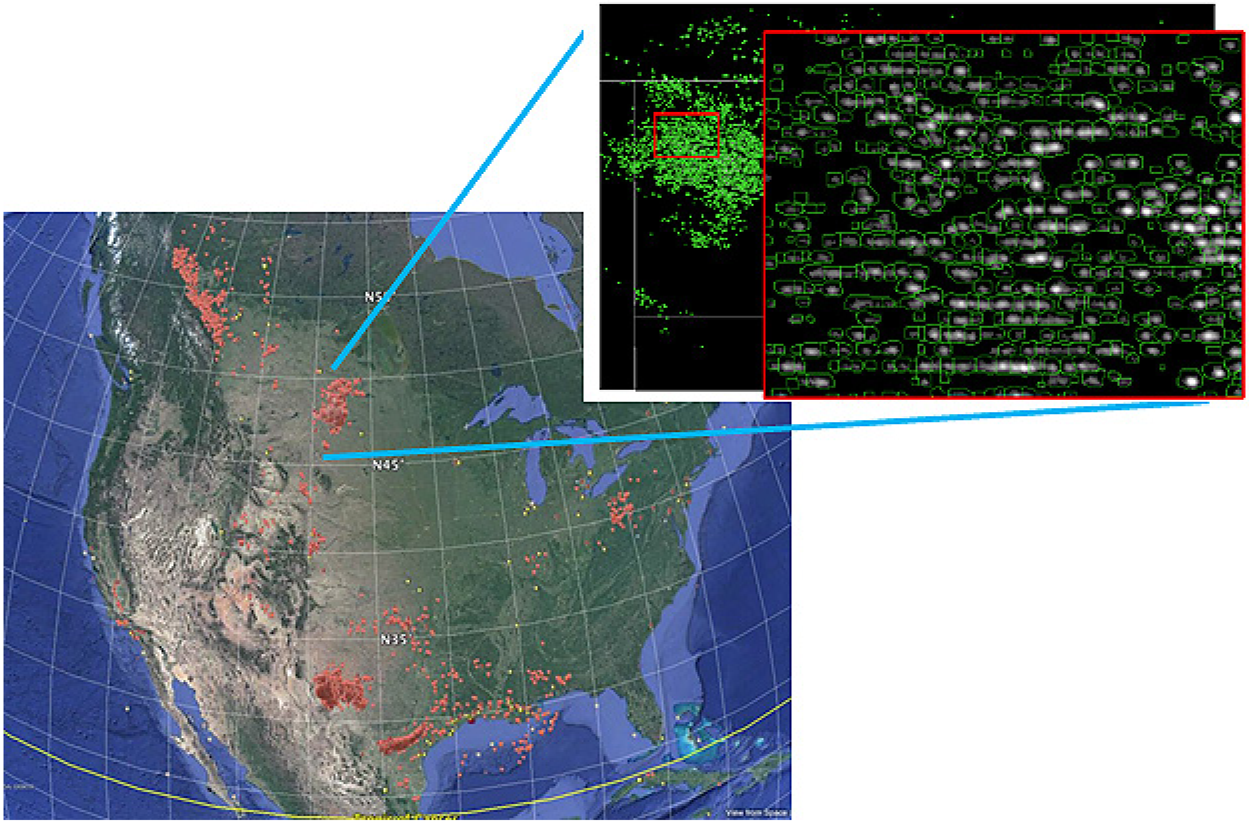
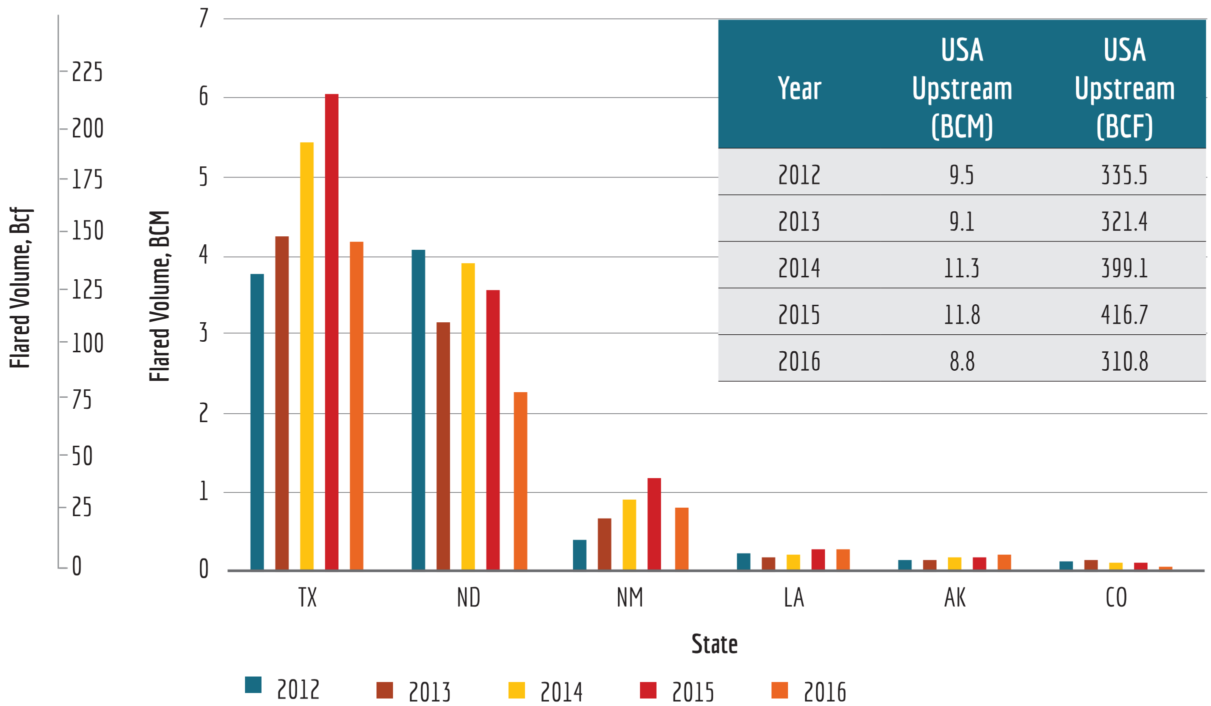


FIGURE 10. Map showing NOAA flare detections over the United States, with close up of North Dakota, highlighting gridded detection output used to estimate flare volumes. *Images courtesy of NOAA.* (Source)[13]

The NOAA assessment estimated the number of flares and the flared volumes for five individual states with relatively high numbers of visible flares (Texas, North Dakota, New Mexico, Louisiana, Arkansas, and Colorado) over a 5-year time period (2012–2016). This data showed that these five states accounted for about 10 billion cubic meters of flared natural gas per year (357 Bcf per year or about 1 Bcf/day) on average during the period (Figure 11). The number of individual flares identified per year in Texas ranged from about 1,700 to 2,600, in North Dakota from about 900 to 1,500, and in New Mexico from about 200 to 400 (Figure 12). These satellite-identified flare numbers appear to represent only large flares above a given size. For example, the number of permitted operating flares in Texas appear to be about 100,000. See Appendix A for a detailed analysis of Texas Railroad Commission (TRRC) flaring data. S&P Global Market Intelligence retrieved

[13] https://www.esrl.noaa.gov/gmd/publications/annual_meetings/2017/slides/5-Zhizhin.pdf



Year	USA Upstream (BCM)	USA Upstream (BCF)
2012	9.5	335.5
2013	9.1	321.4
2014	11.3	399.1
2015	11.8	416.7
2016	8.8	310.8

FIGURE 11. NOAA flare detection data for flared volumes per year in six states over a 5-year time period. *Graphic courtesy of NOAA.* (Source)[14]

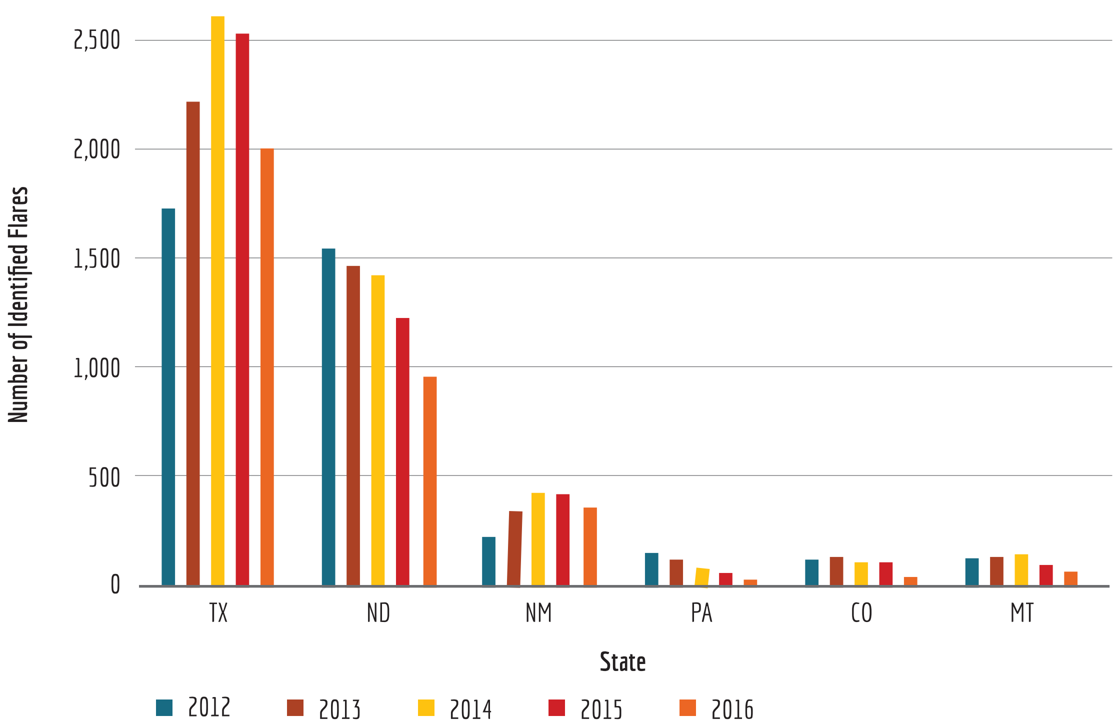


FIGURE 12. NOAA flare detection data for number of identified flares in six states over a 5-year time period. Graphic courtesy of NOAA. (Source)[15]

[14] https://www.esrl.noaa.gov/gmd/publications/annual_meetings/2017/slides/5-Zhizhin.pdf

[15] ibid

several years of global flaring information from NOAA and performed its own spatial aggregation upon the NOAA-calculated values of flared gas volumes for distinct combustion sources in Texas, New Mexico, and North Dakota. The organization next aggregated the data to arrive at a composite annual flared volume for each state.[16] The results, along with the data reported to EIA for the same states, show that an apparent underreporting to EIA, most particularly in Texas and New Mexico (Table 3).

TABLE 3. Comparison of Volumes of Natural Gas Flared in Selected States (Bcf)

Years	New Mexico		North Dakota		Texas	
	NOAA	EIA	NOAA	EIA	NOAA	EIA
2012	14	12	142	80	125	48
2013	24	21	111	103	142	76
2014	31	19	136	130	182	90
2015	42	25	125	107	204	114
2016	31	5	80	70	160	88
2017	23	3	114	89	163	101

The analysis by S&P Global Market Intelligence identifies a number of findings:

- The NOAA combustion estimates exhibit a level of flaring in Texas roughly two-fold higher compared to EIA data over the same time frame.
- According to figures derived from NOAA flaring data, the average annual volume of gas flared in Texas over the years 2012–2017 was 163 Bcf versus an average of 86 Bcf burned each year over the same period according to EIA. That equates to 977 Bcf combusted over 6 years by NOAA data or 516 Bcf according to data from EIA reports.
- Gas flaring activity in 2012 and 2013 in New Mexico, as measured by NOAA and aggregated by S&P, was roughly 15% higher in both years compared with the levels published by the EIA. However, the discrepancy grew considerably in 2014 and 2015, and it widened again in 2016 and 2017. A possible explanation for the widening gap in New Mexico between the two flaring assessment systems could be the inability of gas infrastructure construction to keep pace with the significant increase in drilling, completion, and production in the portion of the Permian Basin located in the southeastern corner of the state. New Mexico crude oil production grew in 2017 by 17.1% to 171 million barrels (MMBbls) from 146 MMBbls in 2016, according to EIA data, while natural gas production from oil wells reported to the EIA increased by 18.7%.
- North Dakota flaring activity, as measured by NOAA and compared with data collected and reported by the EIA, shows closer agreement between the two data sets, compared with observations in Texas and New Mexico. Over the years 2012–2017, NOAA-derived flaring activity has averaged 25% higher than that reported by the EIA. During the years 2013 through 2015, the NOAA and EIA flaring levels were only about 10% apart. However, in 2017, NOAA data indicated a level nearly 30% higher than the 88.5 Bcf reported by the EIA.

[16] Collins, B., 2018, "Are some shale producers under-reporting gas flaring to keep oil flowing?"

The Environmental Defense Fund (EDF) performed a similar analysis of the NOAA data, analyzing flaring rates and volumes in the Permian during 2017. The results indicated that Permian operators alone burned 104 Bcf of natural gas, which equated to 4.4% of all gas produced in Texas in 2017.[17] However, industry only reported 55 Bcf of gas burned to the Texas Railroad Commission (TRRC) in that same year. In the Delaware Basin portion of the Permian, which accounts for about half of all gas produced in the basin, NOAA satellite data shows operators burning almost 8% of produced gas.

In its report on the analysis, EDF calls for the State of Texas to eliminate permanent flaring permits, require new technologies, improve reporting processes and requirements, and eliminate the current exemption for flared gas from the state's 7.5 % natural gas tax to incentivize operators to limit flaring.

Officials of the TRCC, testifying at a hearing of the Senate Natural Resources and Economic Development Committee on January 30, 2019, stated that agency did not believe the EDF study to be accurate, but provided no evidence to refute its findings.

Energy in Depth, a research, education and public outreach campaign funded by the Independent Producers Association of America, stated that "*EDF and S&P relied on a top-down approach to isolate data from subsets of the Permian basin and state-owned University Lands. This can be useful as part of a broader assessment, but it only gives us part of the picture. Getting an accurate measure of flaring rates – like any other methane measurement – would require a combination of top-down and bottom-up assessments.*" [18]

Independent Assessments of Methane Emissions from the Natural Gas System – In recent years, hundreds of researchers have published dozens of studies attempting to estimate the percentage of methane emissions from the nation's oil and natural gas production and delivery systems. Estimates of methane emissions in some regions have been as low as 0.1% and as high as 10% or more in others.[19] Figure 13 includes all recent studies that examine either the full natural gas supply chain or individual oil and gas producing regions where most emissions appear to occur. At the left side of the figure, results from three of the most comprehensive studies (each a meta-analysis in its own right) appear alongside two recent EPA estimates, while the right side of the figure illustrates the range of estimates from studies from specific regions. The left side data shows the most recent figure of about 1.2% for overall losses across the system according to the EPA 2016 GHG assessment (25% of total U.S. anthropogenic methane emissions or a 343 Bcf loss from extraction to distribution), while the right side of the graph illustrates how wide a range of emissions are possible across various elements of the overall system.

[17] EDF, 2019, "Satellite data confirms Permian gas flaring is double what companies report"

[18] EID, February 2019, "Data Limitations Raise Questions about Environmentalists' Claims on Permian Flaring"

[19] Rami, D. and G. Aldana, 2018, "Understanding a New Study on Oil and Gas Methane Emissions"

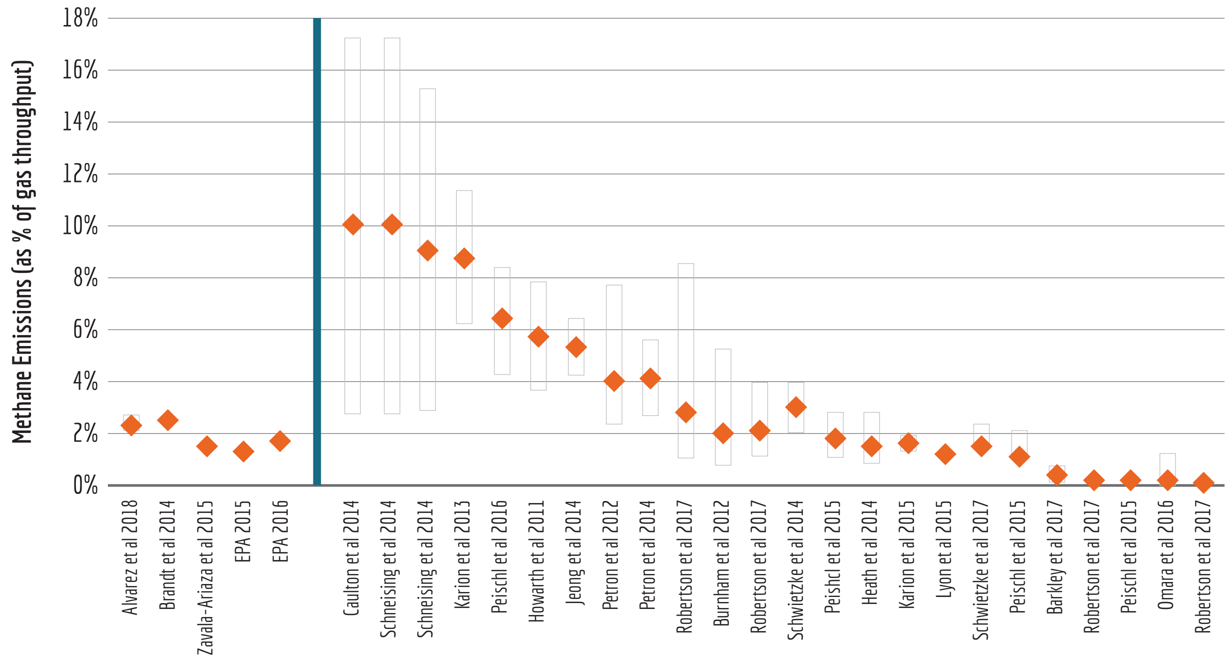


FIGURE 13. Methane emissions as a percent of gas throughput from recent studies. The five data points at left are either meta-studies or annual EPA estimates for the whole natural gas system. Data at right represent individual studies targeting elements of the system. Diamonds represent central estimates. Bars represent confidence intervals or high/low estimates. *Figure based on data from cited studies, courtesy of Daniel Raimi and Gloria Aldana, Resources for the Future.* (Source)[20]

Researchers measure methane emissions from the oil and gas sector using "top-down" and "bottom-up" approaches. The top-down process estimates emissions using methane sensing equipment attached to tower networks, aircraft, drones, or satellites. While the bottom-up method measures emissions using methane detection and measurement equipment at or near the source (e.g., near compressors, at wellheads, within gas processing facilities) and then extrapolate those measurements to produce broader estimates.

FEDERAL FLARING AND VENTING REGULATIONS

Federal laws related to oil and natural gas production equipment and flaring include the following:

- **Quad O** – 40 CFR Part 60, Subpart OOOO ("Quad O" or "*Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced After August 23, 2011*, and on or before September 18, 2015") focuses on rules regarding hydrocarbon emissions from onshore facilities such as storage vessels (tanks), continuous bleed pneumatic controllers, reciprocating and centrifugal compressors, hydraulically fractured wells, equipment leak detection and repair, SO_2 sweetening units, and glycol dehydrators. The final Quad O regulation was issued on **August 16, 2012**.
- **Quad Oa** – In August 2016, Quad O was amended and finalized to include additional regulations, called *40 CFR Part 60, Subpart OOOOa*, which regulates sources of volatile organic compounds (VOCs) and GHGs that were left unregulated under Subpart OOOO

[20] https://www.resourcesmag.org/common-resources/understanding-a-new-study-on-oil-and-gas-methane-emissions/

(e.g., sources such as hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations).

- **Waste Prevention Rule** – The Bureau of Land Management's (BLM's) "*Waste Prevention, Production Subject to Royalties, and Resource Conservation, Final Rule*" also known as the "Waste Prevention Rule" (81 Federal Register 83008, **November 18, 2016**) was promulgated under the authority of the Mineral Leasing Act (MLA) of 1920. Section 225 of the MLA requires BLM to ensure that lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land." BLM's rule targeted natural gas emissions as a potential waste of public resources and loss of royalty revenue. BLM's rule required operators of crude oil and natural gas facilities on federal and Indian lands to take various actions to reduce the waste of gas, established criteria for when flared gas will qualify as waste and therefore be subject to royalties, and clarified which on-site uses of gas are exempt from royalties. In **September 2018**, the current Administration finalized a rollback of the previous Administration's limits (the 2016 Waste Prevention Rule, also known as the Venting and Flaring Rule) on methane that is leaked, vented, or flared from oil and gas wells on federal lands when BLM issued a final rule scrapping a requirement that energy companies seek out and repair leaks and requirements for reducing emissions from well completion, storage vessels, and pneumatic controllers, as well as mandating that companies prepare plans for minimizing waste before getting drilling approvals.
- **EPA New Source Performance Standards – On September 11, 2018**, the EPA proposed changes to the *2016 New Source Performance Standards* for the oil and gas industry. The proposal included changes to the frequency for monitoring fugitive emissions at well sites and compressor stations, requirements for pneumatic pumps at well sites, requirements that a professional engineer certify certain technical actions, and clarification of the acceptable location of separators used during well completions.

Individual states also have their own standards for controlling air quality as it relates to oil and gas production, including flaring regulations that may involve permitting and reporting requirements. These regulations vary considerably from state to state. A number of state agencies also collect data on flaring and venting activity. However, in many cases, the data is submitted voluntarily, and there are no uniform reporting requirements.

It should be recognized that flaring of associated natural gas is driven by a number of factors that can be impacted by federal, state, and local laws and regulations beyond those directly related to flaring or air quality. These include, for example, efforts to restrict or encourage natural gas pipeline construction (lack of pipeline infrastructure or its timely construction increases the need for flaring) and local laws focused on noise and light pollution (large flares are both noisy and bright).

OVERVIEW OF FEDERAL POLICY

CURRENT AND PENDING FEDERAL REGULATORY ACTIONS ON NATURAL GAS FLARING AND VENTING

The federal role in regulating oil and natural gas production focuses primarily on environmental protection, which, in the case of flaring and venting, is focused on air quality. The EPA sets standards on air quality under the authority of the Clean Air Act (CAA). In most cases, the EPA allows states to develop and implement the regulations necessary to meet federal standards. In a few areas, the EPA's regulatory role is more direct, as mentioned previously. Also, BLM has the authority to regulate oil and natural gas production activities taking place on federal lands. Current actions in these areas are listed below.

BLM Venting and Flaring Rule – The most impactful recent change in federal regulations related to natural gas flaring and venting was the Administration's 2018 rollback of the previous Administration's limits on methane leaked, vented, or flared from oil and gas wells on federal lands. BLM issued a final rule removing the requirement that companies seek out and repair leaks, requirements for reducing emissions from a variety or equipment elements, and requirements that companies prepare plans for minimizing waste before getting drilling permits.

What had been known as the Venting and Flaring Rule was tied up in the courts (Montana, Wyoming, and industry lobby groups challenged the rule),[21] but, if implemented, it would have required producers to install emissions control equipment on wells where it was not economic to do so. The producers argued that the rule could lead to the premature plugging of wells before the end of their productive life. The rule was to be applied not only to future wells on federal lands, but also to previously drilled wells, requiring the retrofitting of equipment on marginal wells. For producers who had leases with landowners that might revert to federal mineral ownership at some point in the future, those wells would have become subject to the venting and flaring rule at the time of reversion back to federal ownership. BLM justified the rollback in part by saying the rules were redundant because the EPA also has methane regulations. Now, the rollback of the venting and flaring rule is being challenged in court by California, New Mexico, and environmental groups.[22]

EPA New Source Performance Standards – The EPA announced plans to change course on the regulation of methane and other emissions from the oil and gas industry. The CAA New Source Performance Standards promulgated toward the end of the previous Administration aimed to limit emissions of methane and volatile organic compounds from oil and gas facilities through leak detection and repair requirements (81 Fed. Reg. 35824 - June 3, 2016). The EPA has proposed revisions to respond to previous public comments and to streamline implementation of the rule. Key changes would reduce the frequency of required leak monitoring, extend the amount of time operators have to repair detected leaks, and carve out exemptions to certain detection and repair requirements. The EPA accepted public comments through December 17, 2018, and has not issued a final rule, but it seems likely that a final rule will be issued during 2019.[23]

21 BLM, 2018, "Current Status of Waste Prevention Rule – Partially In Effect"

22 EDF, 2018, "EDF, Allies File Lawsuit Challenging Trump Administration Attack on Methane Waste Standards"

23 Wilmer Hale 2019, "Climate Change Revisions Lead to an Uncertain Regulatory Environment"

U.S. District Court for DC Ruling With Regard to BLM Wyoming Leases – A decision by the United States District Court for the District of Columbia (Wildearth Guardians vs. Zinke, *et al.*) on March 19, 2019 found that the previous Administration violated federal law by failing to adequately take into account the climate change impact of leasing public land for oil gas drilling in Wyoming.[24] The decision, which applied specifically to a 2015 to 2016 plan by the Interior Department's Bureau of Land Management to lease several thousand acres of land for drilling in Wyoming, concluded that the agency was legally required to consider the climate impact of all such lease sales for fossil fuel development. The ruling found that under the National Environmental Policy Act of 1970, federal agencies are required to consider and quantify the effect of the possible planet-warming emissions associated with the fossil fuels to be extracted from the sales of such leases, and that BLM did not adequately quantify the climate change impacts of oil and gas leasing. If the ruling holds up under appeal, it would require the quantification of any flaring and venting activities associated with the exploration, drilling, producing, processing, transportation, distribution and use of the natural gas developed on BLM leases, and the resulting impact on global warming. The Western Energy Alliance, a coalition of fossil fuel companies that joined with the Interior Department in the case, called the decision "ripe for successful appeal."[25]

Federal Energy Regulatory Commission (FERC) – FERC has shifted its policy for analyzing upstream and downstream GHG emissions associated with its review of natural gas projects. Since 2016, FERC's practice had been to include in its pipeline orders estimates of upstream and downstream emissions. In 2017, the D.C. Circuit Court held that FERC must consider and analyze downstream emissions in conducting its review of the National Environmental Policy Act (NEPA). In May 2018, however, a majority of FERC commissioners denied a rehearing request and indicated that FERC's previous practice of analyzing upstream and downstream GHG emissions and the potential climate impacts was generic and speculative. That denial, and FERC's refusal to analyze GHG emissions in its review, has been challenged in the D.C. Circuit Court and is currently being briefed.[26]

Council on Environmental Quality (CEQ) (Executive Office of the President) – On March 28, 2017, The President signed Executive Order 13783, *Promoting Energy Independence and Economic Growth*, which, among other things: (1) directed CEQ to rescind its Final Guidance on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews, 81 Fed. Reg. 51866 (August 5, 2016); and (2) withdrew the Social Cost of Carbon tool for climate change impact analysis. On April 5, 2017, CEQ published a notice in the Federal Register announcing the withdrawal of its GHG guidance. However, some courts are continuing to require an analysis of GHG impacts of proposed actions, which creates continuing uncertainty.[27]

Congressional Action – On February 12, 2019, the U.S. Senate passed the Natural Resources Management Act, a bipartisan bill that designates about 1.3 million acres of wilderness areas, creates six new National Park Service units, and permanently reauthorizes the Land and Water Conservation Fund (LWCF), ***but includes no new regulations regarding venting or flaring of natural gas***. The President is expected to sign the bill if it passes the House.

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[24] https://ecf.dcd.uscourts.gov/cgi-bin/show_public_doc?2016cv1724-99

[25] https://www.nytimes.com/2019/03/20/climate/wyoming-climate-change-drilling-interior.html

[26] Ibid

[27] Ibid

ASSESS POTENTIAL FEDERAL IMPEDIMENTS TO OIL AND NATURAL GAS PRODUCTION

Currently, assuming that the legal challenges to the venting and flaring rule rollbacks are unsuccessful, there are no significant impediments to oil and natural gas production derived from federal regulations on natural gas flaring and venting. Impediments are more likely to arise at the state and local levels and will likely take the form of:

- Legal challenges to the construction of oil and natural gas pipelines by citizen, tribal, and environmental groups, or
- Passage of state regulations or local ordinances that restrict the flexibility of operators in developing leases (e.g., setback rules, zoning laws, conditional use permits).

Such legal challenges or regulatory efforts can face significant legal obstacles depending on the state. Given that the largest and most active tight oil plays (where significant volumes of associated gas are being flared) are in states where such local regulations have not proven to be successful in the past, it is unlikely that any of these challenges will have a significant impact on the restriction of flaring in the near future.

ANALYSIS OF STATE POLICIES AND REGULATIONS

SUMMARY OF IMPACTS AND TRENDS

The 32 oil- and gas-producing states are grouped into three categories for purposes of discussion.[28] The first category (Category I) includes the two states with relatively high levels of natural gas flaring, where there is a likely chance that these levels will increase before infrastructure can be put in place to curtail it. Category II includes states where relatively minor amounts of flaring take place but where the chances of that increasing are also relatively small. Category III includes states where there are very minor instances of flaring and venting and with few known opportunities for any significant development of oil plays with associated gas that would require flaring.

Category 1 States (States with Significant Ongoing and Increasing Flaring Activity)

As shown in Table 4, this group includes Texas and North Dakota, both with significant oil and gas drilling and production activity and gas flaring. The factors listed in Table 4 (and similar tables for the other two categories) are chosen as indicators of the likelihood of potential near term or future methane emissions from the oil and gas sector. The first column (Gas Flaring) is indicative of the degree to which natural gas flaring is currently being practiced. The second column is an indication of the potential for future development of oil plays with associated gas, based on our understanding of undeveloped resources. The third column is an estimate of the relative degree of current methane emissions based on a simple visual inspection of Figure 8, the distribution of oil and gas sector methane emissions (2012 data). EPA does not publish state-by-state estimates of methane emissions from the oil and gas sector. Columns 4, 5 and 6 are 2017 data from the EIA website for flared and vented gas, associated gas production and oil production, respectively.

TABLE 4. Category 1 States Relative Flaring and Venting Indicators

State	Gas Flaring	Undeveloped Associated Gas Potential	EPA GHG Emissions Estimate (2012)	EIA 2017 Flared and Vented (MMcf)	EIA 2017 Associated Gas Production (MMcf)	EIA 2017 Oil Production (MMBbls)
Texas	Significant	Yes	Very High	101,001	1,856,908	1,273
North Dakota	Significant	Yes	High	88,504	9,590	392

MMcf – Million cubic feet MMBbls: Million barrels

[28] As an addendum to this report, thirty-two individual fact sheets for oil- and gas-producing states were prepared. These fact sheets summarize the individual state natural gas flaring and venting regulations, provide links to information sources, and list relevant state contacts. They also provide annual statistics for oil and gas production, flaring and venting and producing wells for the period 2013-2018. Most of these data are obtained from EIA and referenced as such. Data obtained from individual states are also referenced. Flaring and venting and production data provided in the state-by-state discussions in the following sections of this report rely heavily on data from the EIA website and this source is referenced specifically, unless otherwise as noted.

TEXAS

The TRRC has jurisdiction over the permitting of flaring operations in Texas. The Commission's Statewide Rule 32 (16 Texas Administrative Code §3.32) allows an operator to flare gas while drilling a well and for up to 10 days after a well's completion to conduct well potential testing. The majority of flaring permit requests the TRRC receives are to permit flaring of casinghead gas from oil wells. Flaring of casinghead gas for extended periods of time may be necessary if the well is drilled in areas new to exploration where pipeline connections are not available until after a well is completed and a determination is made about the well's productive capability. Other acceptable reasons for flaring include processing plant shutdowns, downstream repairs or maintenance, or existing gas pipelines reaching their capacity.

The analysis of TRRC flaring permits and reported flare volumes indicate that, of the 254 counties in Texas, 200 have permitted flares operating. In 2017, there were roughly 97,000 flares in Texas. Within the 22 counties that make up the Permian Basin, there were about 6,000 flares, which accounted for about 12% of the gas flared in 2017 in the state. The 26 counties that encompass the Eagle Ford play had 15,423 flares and accounted for 35% of the gas flared in Texas in 2017. The other 19 counties across the state having more than 1,000 flares, accounted for a total of 47,553 flares and nearly 40% of the gas flared in Texas in 2017. (***See Appendix A for a more detailed discussion of TRRC flaring data.***)

Flaring has increased significantly in Texas since 2010, primarily due to the development of tight oil plays in the Permian Basin and the Eagle Ford play in south central Texas (Figure 15). From 2016 through May 2018, the TRCC issued more than 6,300 permits, allowing companies to flare across the Permian Basin alone. By comparison, between 2008 and 2010, the TRCC issued fewer than 600 flaring permits for all of Texas.[30] The EIA data shown in Figure 14 indicates that flaring of gas in Texas has fluctuated between 1% and 1.3% of total gas produced during 2013-2017. But in the Permian Basin, the share is 3%, with some individual companies flaring considerably more (e.g., *WPX Energy Inc.* flared 10% of the Permian gas it produced in the first quarter).[31] Some companies are making efforts to reduce flaring by restricting production or building the infrastructure needed to gather the gas. Royal Dutch Shell PLC flared at among the highest rates of large Permian gas producers in the first half of 2018, between 7% and 9%, but reduced to 2.5% in July 2018.[32]

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[29] Note: In the case of North Dakota, the question that arises when viewing the data in this table is: How can the volume of gas vented and flared be so much greater than the volume of associated gas being produced? The EIA uses a gas/oil ratio (GOR) of 6,000 cubic feet per barrel to define the boundary between "gas from gas wells" and "gas from oil wells." A GOR of ‹6,000 means that the gas production is considered to be gas from an oil well (i.e., associated gas), and a GOR of ›6,000 means that the gas is from a gas well. This cut off is defined in order for EIA to make valid comparisons among the states. In addition to gas production from both oil and gas wells, EIA also compiles "shale gas" and coalbed methane production data. According to EIA's definition, gas from "shale wells" may also be considered associated gas if the "shale" play is actually a tight oil play. Most associated gas in ND is produced from the Bakken "Shale" which is primarily a tight oil play. In this case, reported venting and flaring of natural gas in ND is higher than associated gas as only EIA's definition of gas from oil wells is being used and "gas from shale wells" should be added to it. For further detail on how gross withdrawals from oil wells, gas wells, coalbed methane, and shale are classified refer to page 187 of EIA methodology at: https://www.eia.gov/naturalgas/annual/pdf/appendix_a.pdf

[30] Texas Tribune, February 2019, "Railroad commissioners voice doubts that Permian Basin flaring is more prevalent than reported"

[31] WSJ, 2018, "In America's Hottest Drilling Spot, Gas Is Going Up in Smoke"

[32] Ibid.

The TRRC issues flare permits administratively for 45 days at a time, for a maximum limit of 180 days. Extensions beyond 180 days must be granted through a Commission Final Order. If operators want to pursue an additional 45 days past the initial 45-day flare permit time period, they must provide documentation that progress has been made toward establishing the necessary infrastructure to produce gas rather than flare it.

The most common reason for granting an extension to an initial flaring permit is when the operator is waiting for scheduled pipeline construction to be completed by a specified date. Other reasons for granting an extension include operators needing additional time for well cleanup and pending negotiations with landowners.

Operators are required to report volumes of gas flared on their monthly Production Report forms (Form PR) to the TRRC. The Form PR must include actual, metered volumes of both well gas and casinghead gas reported by operators at the lease level. Additionally, current law exempts flared gas from oil wells from the state's 7.5% natural gas production tax.

Oil-targeted wells in the Permian contain an abundance of associated gas. IHS Markit™ projects Permian Basin dry gas production to increase from 7.0 Bcf/day in 2017 to 14.9 Bcf/day by 2023.[33] The primary reason for flaring much of this associated gas in the Permian Basin has been the lack of natural gas pipeline capacity to transport gas to markets. Natural gas constitutes up to 20% of production on a barrel of oil equivalent basis from a typical horizontal tight oil well in the Permian Basin. After four years, this percentage increases to about 50%, but by then, the overall output volume declines about 70% compared to the first year.[34]

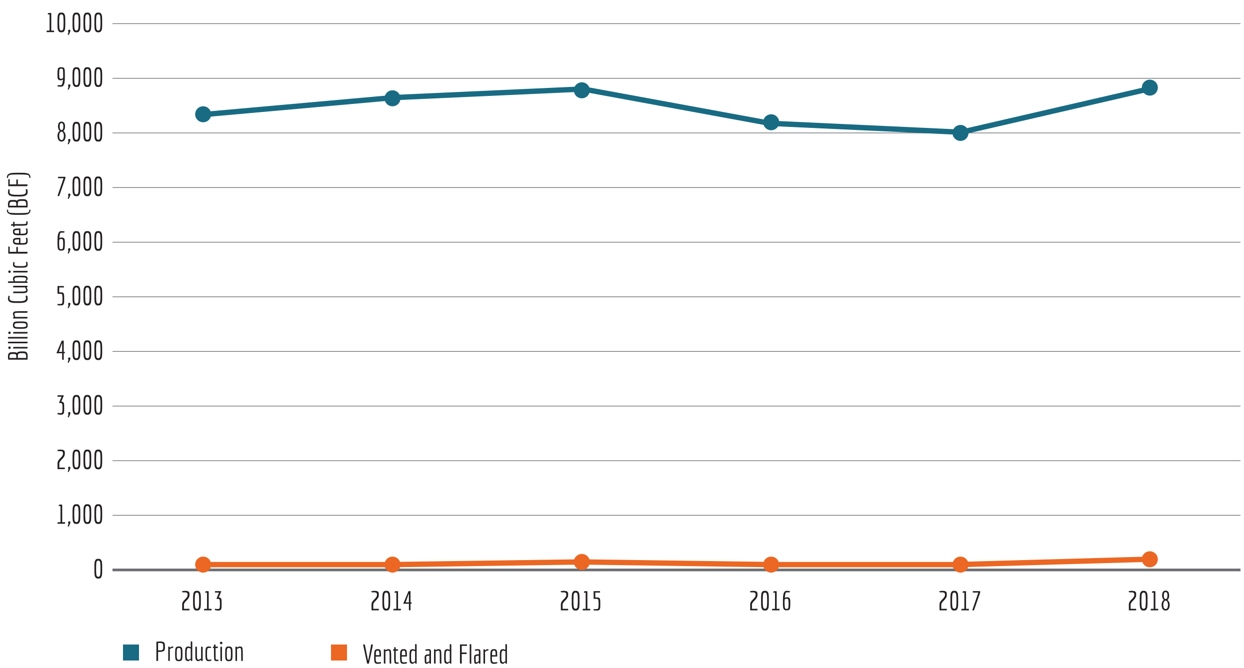

FIGURE 14. Texas venting and flaring vs. natural gas production. Vertical axis units in Bcf per year (*EIA data for 2018 Vented and Flared is not available; data shown is an estimate*). (Data Source: EIA)[35]

[33] IHS Markit, 2018, "The Permian: $308 billion, 41,000 wells, and other key ingredients in the IHS Markit outlook to 2023," May 18, Crude Oil Markets Strategic Report, accessed via NETL subscription

[34] Ibid

[35] https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm

The impact of gas sales on overall well economics is limited in the current market environment; the oil to-gas price ratio has averaged 21:1 during 2018.[36] For example, forgoing all natural gas revenue for the first 6–12 months of a well completed in the Permian's Wolfcamp formation only raises to the break-even oil price (at 10% discount rate) from $42/barrel to $45/barrel—even including the producer compensating the mineral owner for royalties on unsold flared gas volumes.[37]

Accordingly, Permian Basin producers consider holding up oil-centric operations (e.g., delaying well completions or reducing production rates) to wait for gas takeaway capacity to catch up as an immediate loss in income that far exceeds any future income increase resulting from the delay and will seek ways to continue drilling and well completion activities via flaring.

In response to this capacity constraint, several natural gas pipelines are being built or are under development to transport a total of about 10 Bcf/day of gas from the Permian Basin to either Mexico or Gulf Coast liquefied natural gas (LNG) markets over the next several years. These pipelines include the following:

1. The 1.92 Bcf/day **Gulf Coast Express Pipeline** owned by *Kinder Morgan* and partners is expected to come online in the fourth quarter of 2019 (Figure 15).[38]
2. The **Permian Highway Pipeline (PHP)**, designed to move 2 Bcf/day across Texas via a 430-mile, 42-inch diameter pipeline, was approved by *Kinder Morgan Texas Pipeline LLC (KMTP)*, and partners *ExxonMobil* and *EagleClaw Midstream Ventures LLC. PHP* could be in service by late 2020 and will run from Waha in West Texas to Katy, outside of Houston, with connections to the Gulf Coast and Mexico markets (Figure 16).[39]
3. The 1.85 Bcf/day **Pecos Trail Pipeline** owned by privately held NAmerico and Cresta Energy is a 468-mile, 42-inch pipeline from the Permian basin to Corpus Christi and is expected to come online by 2020 (Figure 16).[40]
4. The **Permian-Katy Pipeline (P2K)**, owned by *Sempra Energy and Boardwalk Pipeline Partners*, is proposed to transport 1.5 to 2.25 Bcf/day and is expected to be in service in the fourth quarter of 2020 (Figure 16).[41]
5. The 2.0 Bcf/day **Permian Global Access Pipeline (PGAP)** to be developed by Tellurian is a 625-mile, 42-inch pipeline expected to come online by the end of 2022 (Figure 16).[42]

Even if all of these proposed pipelines are not completed and increased drilling in tight oil plays contributes to the volumes of associated gas currently being flared in the Permian Basin, the increased capacity will almost certainly enable a larger share of the associated gas to be captured and sold. An analysis by IHS Markit in May 2018 projects that sufficient natural gas pipeline capacity will be available after 2020 to meet the current projected increase in demand.[43]

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[37] IHS Markit, 2018, "The Permian: $308 billion, 41,000 wells, and other key ingredients in the IHS Markit outlook to 2023," May 2018, Crude Oil Markets Strategic Report, accessed via NETL subscription

[38] PGJ, 2017, "Letter of Intent Signed to Develop Gulf Coast Express Pipeline"

[39] NGI, 2018, Permian Highway Project Advancing to Move 2 Bcf/d to Gulf Coast and Beyond

[40] Seeking Alpha, 2018, "Permian Basin: These Oil and Gas Pipeline Projects Will Narrow The Oil And Gas Discounts In 2020"

[41] Ibid.

[42] OGJ, 2018, "Flat near-term pipeline plans buoyed by U.S. growth"

[43] IHS Markit, 2018, "The Permian: $308 billion, 41,000 wells, and other key ingredients in the IHS Markit outlook to 2023," May 2018, Crude Oil Markets Strategic Report, accessed via NETL subscription

In the meantime, the TRRC appears to be unlikely to take action to restrict oil production to reduce flaring. Texas officials indicated that they expect the issue to resolve itself eventually once the necessary infrastructure is built. The *Wall Street Journal* reviewed data on the more than 20,000 permit requests that companies submitted to the TRRC to flare gas over the past 5 years, and, as of August 2018, data show that none had been denied.[44] In June 2018, the TRRC Commissioner was quoted saying *"This is not a simple thing we're talking about. It'd be a pretty big policy shift and we want to be very thoughtful about what the ramifications [of restricting flaring] could be."* He also said at that time (June 2018) that the TRRC hoped to make a decision within 6 months.[45]

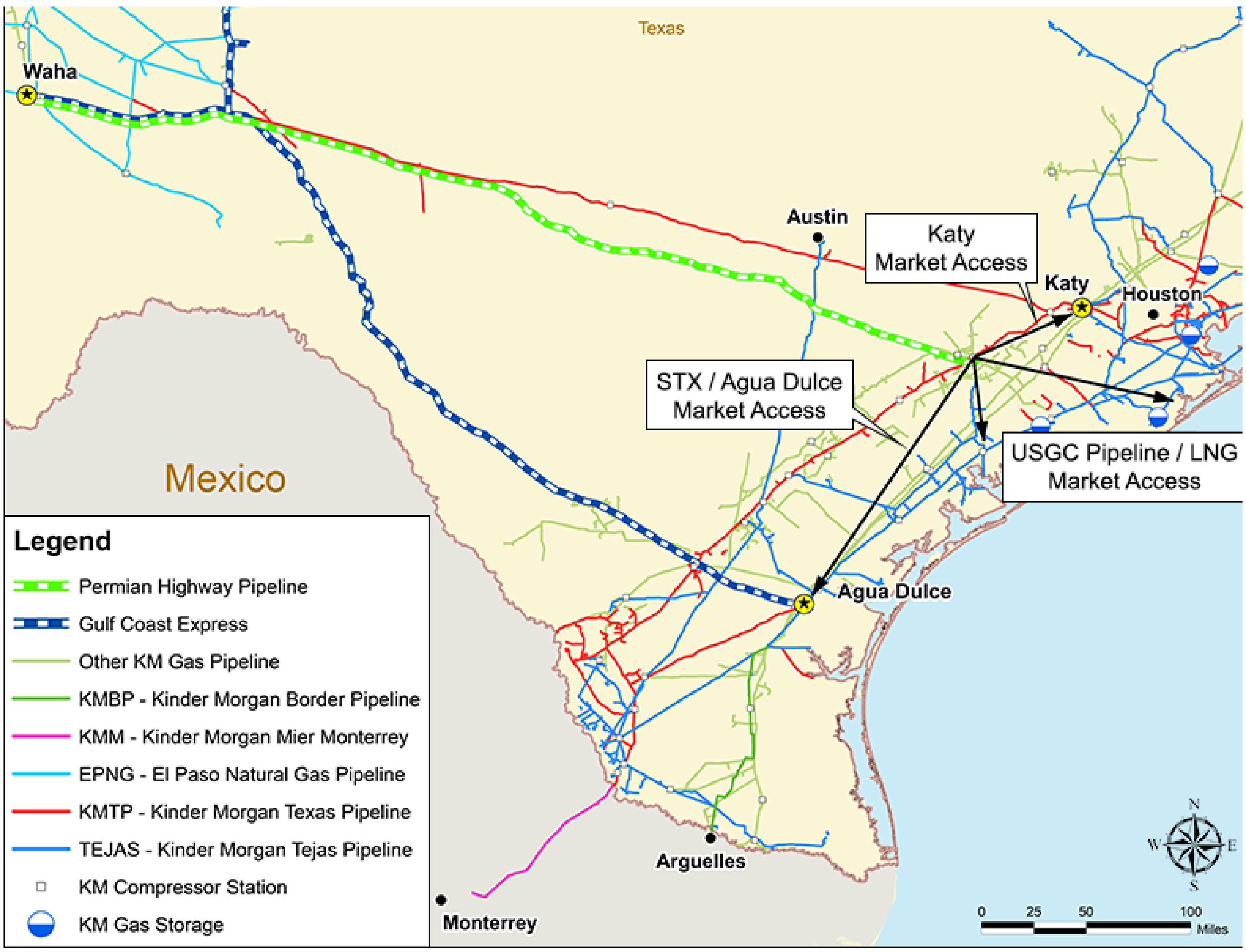

FIGURE 15. Map showing the routes for two Kinder Morgan natural gas pipelines (Gulf Coast Express and Permian Highway Pipeline) currently under development to connect the Permian basin with Gulf Coast and Mexico markets. *Map courtesy of Kinder Morgan.* (Source)[46]

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[44] WSJ, 2018, In America's Hottest Drilling Spot, Gas Is Going Up in Smoke

[45] Bloomberg, 2018, "Gas Glut in Permian Sparks Dilemma Over How Much to Burn"

[46] https://www.kindermorgan.com/pages/business/gas_pipelines/projects/php/

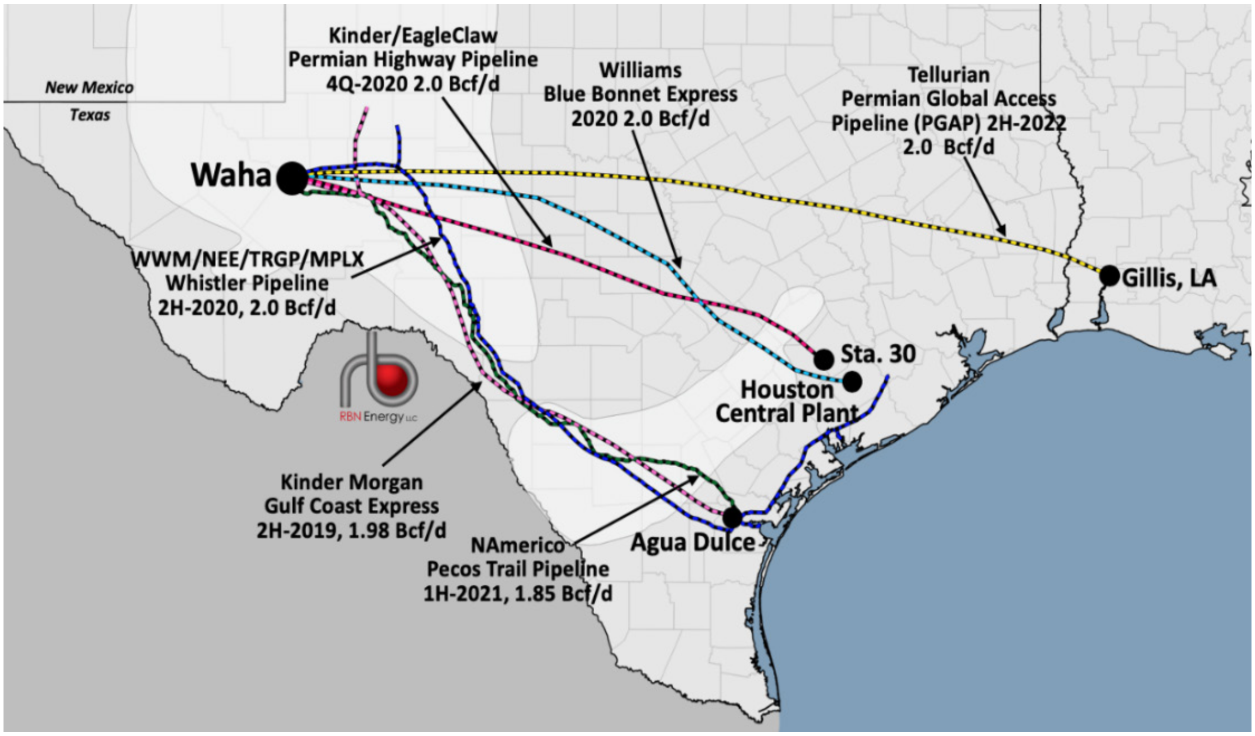

FIGURE 16. Map showing the routes for additional natural gas pipelines currently in development to connect the Permian Basin with Gulf Coast and Mexico markets. *Map courtesy of RBN Energy, LLC.* (Source)[47]

NORTH DAKOTA

The State of North Dakota bans the venting of natural gas and requires that casinghead gas be burned through a flare with the estimated volume flared reported to the director of the oil and gas division at the North Dakota Department of Mineral Resources. All oil and gas wells within the state must be registered with the North Dakota Division of Air Quality and adhere to emission controls. Permitting requirements are applicable for oil or gas well production facilities that are classified as a major stationary source or a major modification. These requirements include the prevention of significant deterioration (PSD) of air quality—a number that is calculated based on the average daily amount of gas flared per day. All flares must adhere to regulations regarding Requirements for Organic Compounds Gas Disposal, Restrictions Applicable to Flares, and Controls of Emissions from Oil and Gas Well Production Facilities. These regulations include requirements that the flare must be operational and capable of proper combustion at all times.

The North Dakota Industrial Commission (NDIC) established Order No. 24665 as a system of gas capture to reduce the volume of natural gas flared in the state. This Order established a drilling permit review policy that requires producers to submit a gas capture plan with every drilling permit application. This Order also requires that producers submit gas capture plans at permit hearings. These plans must include information on area-gathering

47 https://seekingalpha.com/article/4186260-permian-basin-oil-gas-pipeline-projects-will-narrow-oil-gas-discounts-2020

system connections and processing plants, the rate and duration of planned flowback, current system capacity, a timeline for connecting the well, and a signed affidavit verifying that the plan has been shared with area midstream companies.

North Dakota flaring as a percentage of gas produced fell significantly between 2014 and 2016; however, it has trended upward over the past 2 years (Figure 17).

This is partly due to the combination of better technology, which results in higher production rates and more wells being drilled in the core areas of the Bakken Shale, where gas-to-oil ratios are higher. During the downturn in oil prices, operators focused on drilling in the core area of the Bakken, where wells produce more gas. This caused the state's associated natural gas production to continue growing even as oil production dropped.

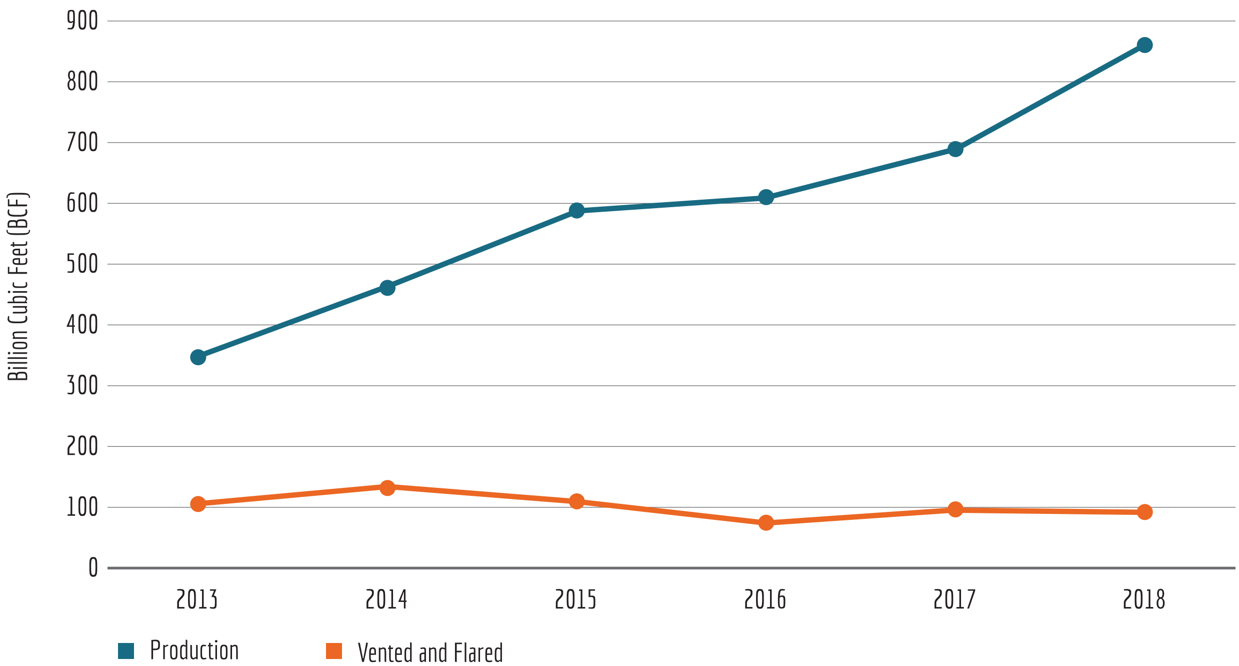

FIGURE 17. North Dakota natural gas production and vented and flared gas. Vertical axis in Bcf per year. (EIA data). (Data Source: EIA)[49]

In April 2018, the NDIC amended the flaring reduction rules to make the following allowances:

- Allow companies drilling outside of the core areas of western North Dakota's oil patch to drill multiple wells for up to 1 year without capturing the gas
- Allow operators to accumulate credits over a 6-month time period instead of only 3 months
- Give companies credit if the natural gas they produce is used in the state to power equipment or facilities
- Allow companies that are meeting targets to forgo a capturing plan with their drilling permit applications.

[48] Williston Herald, 2018, "North Dakota relaxes flaring rules"

[49] https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_a.htm

In November 2018, the NDIC made additional changes due to the high rate of growth in gas production.[50] The NDIC revised the goals of the gas capture policy to focus on increasing the volume of captured gas, rather than reducing the flared volume. The NDIC also removed the goals related to reducing the number of wells flaring and reducing the duration of flaring, and instead added a goal of incentivizing investments.

The NDIC Order No. 24665 establishes the following goals for capture of associated gas: 85% for November 1, 2016, through October 31, 2018; 88% for November 1, 2018, through October 31, 2020; and 91% beginning November 1, 2020. North Dakota's gas production was 2.5 Bcf/day in December 2018, according to the January production report, but it also flared 18.75% of that, rather than the 12% targeted.[51] The statewide monthly gas capture goal of 85% prior to November 2018 had been missed multiple times over the year.

Of the flared volume, 75% comes from wells that are connected to a pipeline, but are connected where the pipeline, natural gas processing plant, or other infrastructure is inadequate to capture all of the gas. The remaining 25% of flared gas comes from wells that are not yet connected to a pipeline.[52]

Several natural gas processing plants are under construction or in development to catch up to the production. North Dakota's natural gas processing capacity is insufficient; and, while most wells are connected to pipelines, the pipeline capacity is insufficient to capture the volumes of gas being produced.

The NDIC decided to maintain the current 88% goal while waiting to see how new federal regulations will affect the accounting of gas flared at Fort Berthold, where capture rates have been just 71%. The BLM is going to defer regulation of methane emissions to tribal and state governments; and, if this occurs, the NDIC may be able to meet its goal despite continued excess flaring statewide.[53] State regulators are meeting with the BLM to develop a memorandum of agreement by early 2019.

North Dakota regulators have struggled with unauthorized flaring by producers and have sought methods to track down violators. The state plans to require producers who exceed allowed flaring levels of 15% of production to shut down their wells until gas infrastructure construction has caught up with demand. Eleven companies captured less than 85% of Bakken natural gas in September 2018.[54]

Expansion of both natural gas processing and natural gas liquids pipeline takeaway capacity are critical to reducing flaring in North Dakota. Plans for both are in place but the expansions, scheduled to be in place by 2019–2020, may not be enough to handle projected production increases beyond 2021–2024 (Figure 18 and Figure 19).

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[50] NDIC, 2018, "North Dakota Industrial Commission Order 24665"

[51] NDIC production data download

[52] Kringstad, J., 2019, NDIC Update

[53] Williston Herald, 2018, "North Dakota relaxes flaring rules", https://www.willistonherald.com/news/north-dakota-relaxes-flaring-rules/article_8d-8f99bc-ef44-11e8-98da-db6c204faed6.html

[54] None were required to restrict oil production per Bismarck Tribune, 2018, "North Dakota oil production, natural gas flaring reach new highs"

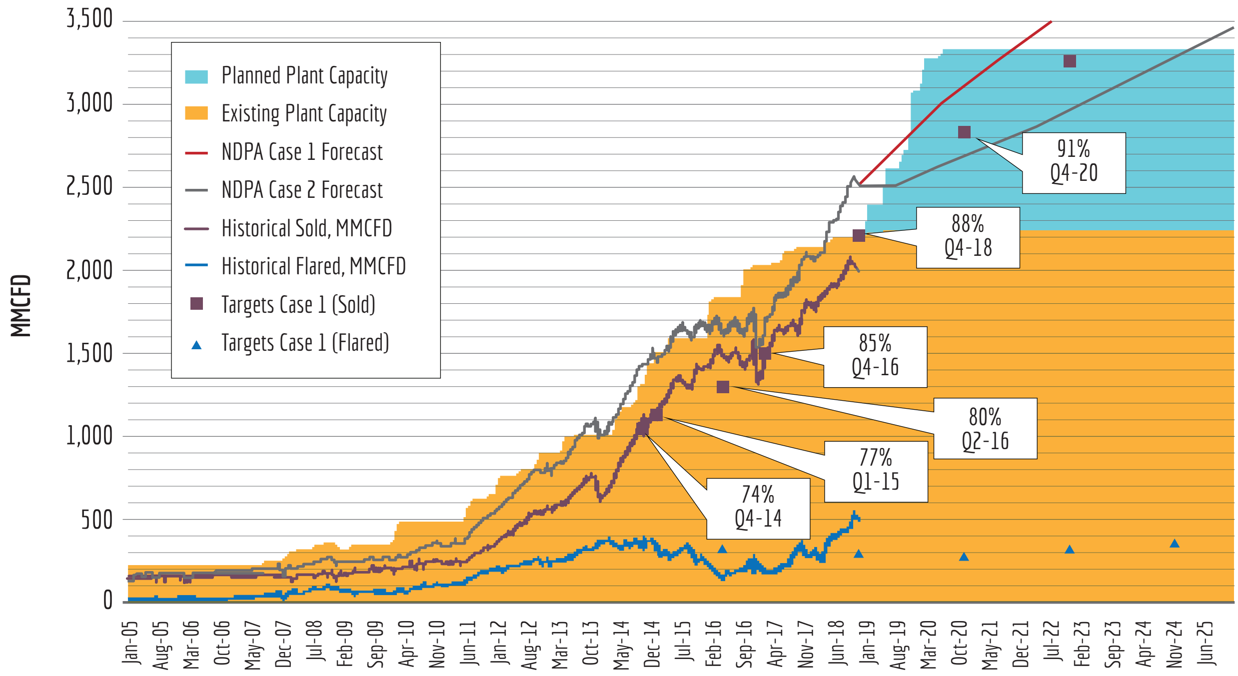

FIGURE 18. Current and predicted associated gas production compared to current and planned gas processing plant capacity. Projections assume current technology and enhanced oil recovery is not included. *Graphic courtesy of J. J. Kringstad – North Dakota Pipeline Authority.* (Source)[55]

Additional interstate gas transmission pipeline capacity is also needed. The North Dakota Pipeline Authority reports that natural gas-related projects costing at least $3 billion are scheduled to come on line within the next 2 years, boosting gas-gathering and processing capacity by 38%.[56] MDU Resources Group recently announced that subsidiary WBI Energy plans to construct the North Bakken Expansion Project, adding 67 miles of pipeline in Williams and McKenzie counties.[57] The project will transport 200 million cubic feet (MMcf)/day of natural gas that has been processed from the Tioga area to a new connection with Northern Border Pipeline in McKenzie County. The $220 million project also includes two compressor facilities and other related infrastructure, and it will be critical to relieving a transportation bottleneck in the core of the Bakken. The proposed pipeline could be expanded to transport up to 375 MMcf/day if there is enough demand. If permitting is approved, construction is expected to begin in early 2021 and be completed late that year.

[55] https://ndpipelines.files.wordpress.com/2019/02/ndic-ndpa-slides-2-12-19-full-page.pdf
[56] North Dakota Industrial Commission Update, February 2, 2019
[57] Bismarck Tribune, 2019, "Natural gas pipeline proposed for northwest North Dakota"

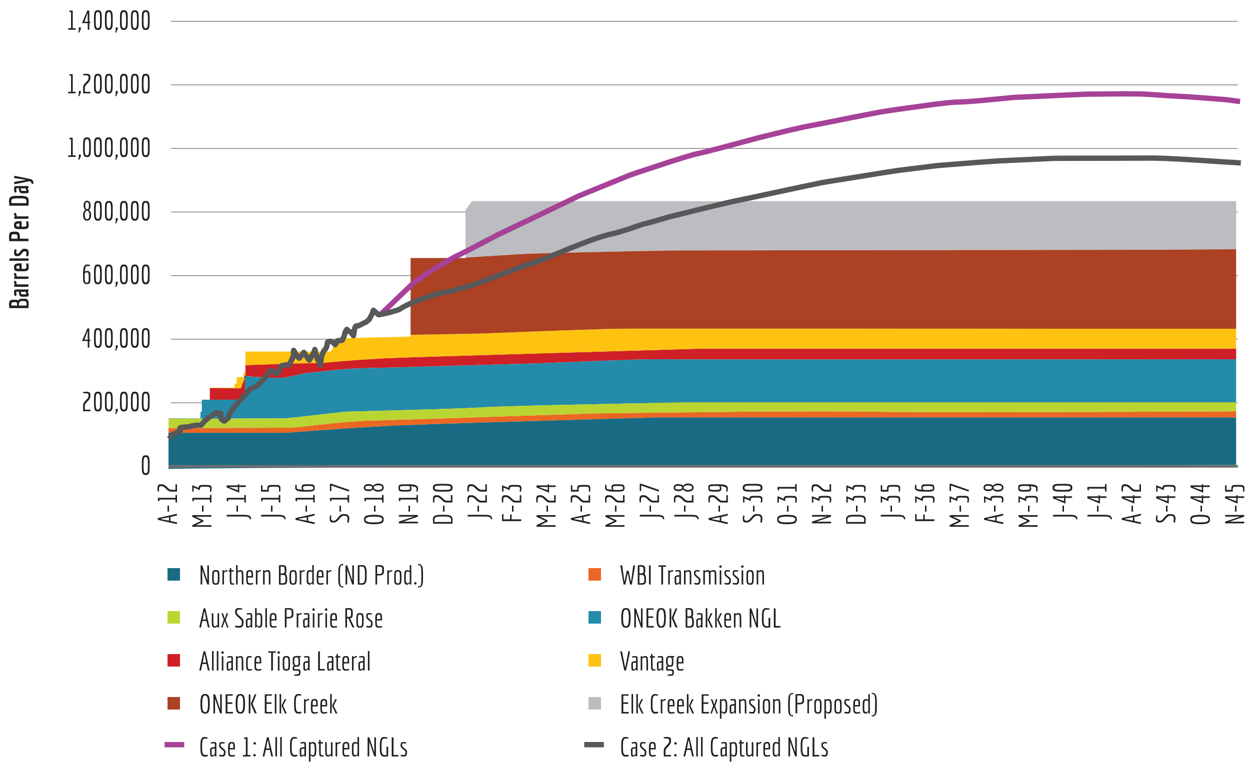

FIGURE 19. Current and predicted Natural Gas Liquid (NGL) production compared to current and planned NGL pipeline takeaway capacity. *Graphic courtesy of J. J. Kringstad – North Dakota Pipeline Authority*. (Source)[58]

[58] Ibid

Category 2 States (States Where Limited Flaring Occurs and Likelihood of Increase Is Limited)

Table 5 lists 11 states that exhibit a combination of current gas flaring, potential for development of oil plays with associated gas, medium to high levels of methane emissions based on EPA accounting, and significant oil and gas drilling and production activity. While the volumes of gas flared in these states are relatively small compared to Group 1 states, there is a possibility that a combination of rapid oil play development and regional pipeline capacity constraints could lead to pressure to increase natural gas flaring.

TABLE 5. Category 2 States Relative Flaring and Venting Indicators

State	Gas Flaring	Undeveloped Associated Gas Potential	EPA GHG Emissions Estimate (2012)	EIA 2017 Flared and Vented (MMcf) *	EIA 2017 Associated Gas Production (MMcf)	EIA 2017 Oil Production (MMBbls)
Wyoming	Yes	Possibly	High	9,132	58,547	76
Alaska	Yes	Yes	Low	7,605	3,167,757	180
Louisiana	Yes	Yes	High	5,178	36,071	52
Colorado	Yes	Possibly	High	4,279	221,288	131
Montana	Yes	Possibly	Medium	3,123	21,099	21
New Mexico	Yes	Yes	High	2,984	302,555	171
Utah	Yes	Possibly	Medium	No	39,834	34
Oklahoma	Yes	Yes	High	No	188,440	166
Pennsylvania	Yes	No	High	No	3,014	7
West Virginia	Yes	No	High	No	1,553	9
Kansas	Yes	Possibly	High	No	0	36

* States ranked in order of flared and vented associated gas volumes.

NEW MEXICO

The New Mexico Oil Conservation Division (OCD) is the primary regulator of oil and gas development and production in New Mexico (the equivalent of the TRRC in Texas).[59] The OCD gathers oil and gas well production data, permits new wells, enforces New Mexico's oil and gas laws and rules, and ensures oil and gas development is conducted in a way that protects human health and the environment. OCD also administers oil and gas-related aspects of the Water Quality Act and regulates the development and production of geothermal resources under the Geothermal Resources Conservation Act.

The New Mexico Environment Department's Air Quality Bureau (AQB) oversees odors and air contaminants through the Air Quality Control Act.[60] This state regulatory agency ensures air quality standards are met, enforces regulations, and monitors relevant emissions data. AQB maintains and updates the Emissions Databases that report emission data from each active oil and natural gas facility.[61] A variety of emissions are measured and monitored to enforce state and federal regulatory compliance.

The New Mexico Administrative Code (NMAC) delineates the official rules that have been filed by all of the state's agencies. Venting and flaring regulation guidance is found under Chapter 15, Title 19, Subsection 18: Production Operating Practices.[62] These rules state that an operator shall not flare or vent casinghead gas produced from a well after 60 days following the completion of a well.[63]

Exemptions to the rule exist and can be enacted by obtaining a permit. These exemptions include mechanical difficulties, associated gas having no commercial value, and "when the flaring or venting casinghead gas appears reasonably necessary to protect correlative rights, prevent waste or prevent undue hardships on the applicant." This same subsection states that casinghead gas must be metered and any sold or transported away from the facility must be reported—with the exception of that which is permitted to be flared.

The AQB enforces air pollution through the Air Quality Control Act of New Mexico. This limits excess GHG emissions from production. Chapter 74 of the New Mexico Statutes Annotated 1978 (NMSA) defines limits and detail permit requirements for emissions contributing to air pollution.[64] These regulations are less related to specific venting and flaring requirements, but rather overall facility compliance.

The majority of flaring of associated gas in New Mexico takes place in the Permian Basin in the southeastern corner of the state, where it covers all or parts of Lea, Eddy, Chaves, and Roosevelt Counties. Crude oil output from this part of the state has more than doubled over the last 4 years. The same problem that results in high volumes of gas flaring immediately across the Texas border to the east—the lack of natural gas pipeline infrastructure capacity—is the driver behind increased levels of flaring in southeastern New Mexico.

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59 New Mexico Oil Conservation Commission

60 New Mexico Environment Department, Air Quality Bureau

61 New Mexico Environment Department's Emissions Analysis Tool

62 New Mexico Administrative Code; Title 19: Natural Resources and Wildlife, Chapter 15: Oil and Gas, Part 18: Production Operating Practices (19.15.18 NMAC)

63 New Mexico Administrative Code; Title 19: Natural Resources and Wildlife, Chapter 15: Oil and Gas, Part 18: Production Operating Practices (19.15.18 NMAC)

64 Chapter 74 of the New Mexico Statutes Annotated 1978 (NMSA)

The New Mexico OCD has not made any amendments to laws regulating venting and flaring since 2008. In November 2015, the OCD Non-Transported Disposition Code, which requires the reporting of volumes of flared and vented gas, became effective. In March 2017, another notice was issued that only 51 of the 603 operators were reporting the correct volumes of waste gas.

However, more recent evidence appears to indicate that oil and gas producers have achieved some success in capturing methane emissions. According to the EPA, methane emissions fell by 47% in the San Juan Basin, and they dropped by 6% in the Permian Basin between 2011 and 2016 and another 6% between 2016 and 2017. New Mexico state regulators reported a decrease of more than 50% of methane being vented or flared in 2017.[65]

However, the incoming New Mexico Governor has pledged to address methane flaring and emissions resulting from leaks from faulty equipment. On February 4, 2019, the Governor signed an executive order directing New Mexico's state agencies to move expeditiously to develop comprehensive, statewide methane regulations to cut energy wasted from the oil and gas industry and improve air quality.[66] The Governor has directed the Energy, Minerals, and Natural Resources Department (EMNRD) and Environment Department to work cooperatively on complementary, but not duplicative, rules. The EMNRD's Oil Conservation Division would develop statewide rules focused on cutting energy and revenue waste from practices like venting and flaring, while the Environment Department's Air Quality Bureau could complement these efforts with its own set of requirements focused on improving air quality.

ALASKA

Waste of oil and natural gas is prohibited by the Alaska Oil and Gas Conservation Act. Such waste includes things such as the release of gas, burning of gas, or escape into the open air of gas from a well producing oil or gas, unless authorized by the Alaska Commissioner of Natural Resources. Any instance of wasted oil or natural gas must be reported to the Oil and Gas Conservation Commission (AOGCC) along with a statement of compliance actions. Flaring is also prohibited except in the case of emergency or system testing. Any release of gas (other than incidental *de minimis* venting) must be reported to the AOGCC with a written supplement that includes volumes vented or flared for any incident that exceeds one hour. Additionally, operators are required to minimize the volume of gas released by utilizing good oil field engineering practices. Any gas released, burned, or permitted to escape into the air constitutes waste, except in the following situations:

- Flaring or venting gas for a period not exceeding one hour as the result of an emergency or operational upset is authorized for safety
- Flaring or venting gas for a period not exceeding one hour as the result of a planned lease operation is authorized for safety
- Flaring pilot or purge gas to test or fuel the safety flare system is authorized for safety
- *De minimis* venting of gas incidental to normal oil field operations is authorized
- Flaring or venting of gas for a period exceeding one hour if the flaring or venting is necessary for facility operations, repairs, upgrades, or testing procedures is authorized at the AOGCC's discretion.

[65] NMGO, 2019, "NM killing goose that lays golden eggs"

[66] EDF, 2019, "No time to waste: What lies ahead in New Mexico on methane policy?"

The AOGCC, the Alaska Department of Environmental Conservation (DEC), and the EPA currently regulate flaring, venting, and fugitive emissions by the oil and gas industry in Alaska.

The AOGCC held a hearing in December 2018 in response to a citizen's request seeking to prevent all non-emergency venting and flaring in Alaska. Comments from the Alaska Oil and Gas Association[67] claimed that this would be impractical and unsafe. A significant portion of gas flared on the North Slope is due to production fluctuations, process upsets, equipment failures, equipment purging, and gas from equipment pilots, all of which are non-emergency situations but critical to safe operations.

There are a large number of basins onshore and offshore in Alaska, where future development could take place and pipeline infrastructure is absent. If economics ever justify the development of oil plays with associated gas, there is a possibility that a need for significant flaring could occur. Natural gas on the North Slope is reinjected (for the most part), and that practice will likely continue in the event new oil fields are developed.

COLORADO

The Colorado Oil and Gas Conservation Commission (COGCC) is responsible for regulating the state's oil and gas development, according to rules outlined in the Colorado Code of Regulations. Rule 912 of 2 CCR 404-1 addresses natural gas flaring and venting, calling for the prohibition of unnecessary or excessive venting or flaring from a well. Regulations relevant to venting and flaring are also outlined in the Oil and Gas Conservation Act.

Colorado's regulation of emissions from the state's oil and natural gas sector began in 2004, requiring the installation of air pollution control technology to achieve at least a 47.5% reduction in Volatile Organic Compound (VOC) emissions from exploration and production operations, natural gas compressor stations, and natural gas drip stations located in the Early Action Compact (EAC) plan area. These controls were focused largely on VOC flash emissions from condensate tanks. Between 2006 and 2008, Colorado's Air Quality Control Commission (AQCC) approved additional regulations to require further reductions in condensate tank flash VOC emissions and glycol dehydrator emissions.

In 2014, Colorado became the first state to regulate methane emissions from oil and gas drilling, with the goal of shrinking its carbon footprint and improving local air quality. In February 2014, the AQCC passed a comprehensive new set of regulations aimed at additional VOC and hydrocarbon/methane reductions from the Colorado oil and gas sector. The new provisions went above and beyond EPA's Quad O New Source Performance Standard, applying new and additional control requirements to all oil and gas operations statewide and addressing all hydrocarbons, not just VOCs. The regulations also required operators of new and existing facilities to implement Storage Tank Emission Management (STEM) system and Leak Detection and Repair (LDAR) programs. Further requirements included upgrades to pneumatic controllers; increased controls for glycol dehydrators; increased flare combustion efficiency to 98%; new requirements for compressor seals and open-ended valves or lines; emissions controls for new, modified, existing, and re-located natural-gas fired reciprocating internal combustion engines; and new well liquid unloading requirements, among other requirements (collectively referred to

[67] Alaska Oil and Gas Association, Letter to Commissioner Hollis French, Re: Kate Troll Petition re: Non-Emergency Venting / Flaring," December 18, 2018

as “the Regulation No. 7 Program”). As of January 1, 2016, the Regulation No. 7 Program was fully operational.

Since Colorado’s rules went into effect, leakage rates dropped by 75% and, in a recent survey, 7 out of 10 producers said the benefits outweighed the costs, and most said the costs were not especially high since they can be recouped through a boost in sales.[68]

Colorado has a fairly well-developed natural gas pipeline gathering system throughout the Denver-Julesberg Basin, the most likely area for growth in oil production from the Niobrara Play. The need for a significant increase in flaring of associated natural gas does not appear to be likely; plus, given that the state’s emissions control regulations are considered a “gold standard” among many, increased emissions are seen to be unlikely.

On March 18, 2019, Colorado’s House Energy and Environment Committee approved Senate Bill 181, which would have a significant impact on oil and gas operations in Colorado, and it would give local governments a greater say in where the oil and gas facilities will be located. The bill will go to the House Finance committee next.[69]

LOUISIANA

The Geological Oil and Gas Division within the Office of Conservation at the Louisiana Department of Natural Resources (LDNR) regulates the waste of oil and gas, with the goals of conserving natural resources, preventing the drilling of unnecessary wells, and protecting the correlative rights of mineral owners.[70] The Louisiana Department of Environmental Quality (LDEQ) administers air quality regulations and permitting programs in Louisiana through its Office of Environmental Services.[71] There are two primary pieces of legislation impacting natural gas flaring and venting in the Louisiana Administrative Code, Title 33, Environmental Quality, Part III (which concerns air quality and authorizes administrative authority to LDEQ) and Title 43, Natural Resources, Part XIX (which concerns the Office of Conservation and authorizes administrative authority to LDNR).[72, 73] Natural gas flaring and venting are prohibited in the State of Louisiana unless the LDNR approves an operator’s application for exemption due to economic hardship. The regulations note that no economic hardship can be found if the current market value of natural gas exceeds the cost involved in making the gas available to market.[74] The LDEQ’s *Regulatory Permit for Oil and Gas Well Testing* can be used to permit temporary flaring and venting for the purpose of well testing and to establish the proper design of a permanent fluid-handling facility.[75]

Reported flaring has increased steadily during 2012–2017, from about 3,600 MMcf to about 5,200 MMcf. This increase is more than likely associated

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68 Newsweek, February 8, 2017, “Colorado’s Successful Methane Emissions Program Is a Gas to Congress”

69 Denver Post, May 27, 2016, “Colorado’s tougher approach to oil and gas advances in House as Democratic lawmakers weigh climate change push”

70 Louisiana Department of Natural Resources, Office of Conservation

71 Louisiana Department of Environmental Quality, Office of Environmental Services

72 Louisiana Department of Environmental Quality, Title 33, Environmental Quality

73 Title 43, Natural Resources, Part XIX. Office of Conservation General Operations Subpart 1. Statewide Order No. 29-B

74 Title 43, Natural Resources, Part XIX. Office of Conservation General Operations Subpart 1. Statewide Order No. 29-B

75 Louisiana Environmental Results Program, Field Guide to Environmental Compliance for Oil and Gas Exploration and Production Operations, April 2012

with increased development of unconventional gas and oil plays such as the Deep Tuscaloosa/Austin Chalk/Tuscaloosa Marine Shale trend across central Louisiana and the dry gas prone Haynesville-Bossier play of Louisiana and Texas. There is a chance that flaring could continue to increase slowly as these trends continue, but an increase—like what has taken place in Texas or North Dakota—is not likely. These plays are not high gas/oil ratio (GOR) oil plays, and there is significant natural gas pipeline infrastructure across Louisiana. There may be some north-to-south pipeline capacity issues if Haynesville gas production increases and must compete with northern Appalachian gas moving south to the Gulf Coast, but this would not generate increased flaring.[76]

WYOMING

The Wyoming Oil and Gas Conservation Commission (WOGCC) is the state agency authorized to regulate oil and gas drilling and production on state-owned and private land. The Wyoming Department of Environmental Quality is not involved with flaring or venting; it only has requirements related to tank flashing controls if a well operation surpasses an uncontrolled emissions threshold. Authorization for flaring and venting of gas is included within WOGCC's Rules and Regulations under Chapter 3, Section 39. Effective in April 2016, this guidance allows for flaring and venting during the following situations:

- Emergencies or upset conditions that result in unavoidable short-term venting or flaring
- Well purging and evaluation tests
- Production tests (maximum of 15 days)
- Low-rate casinghead gas from individual oil wells (less than 60 thousand cubic feet/day).

Special approval is also necessary for venting gas that contains a hydrogen sulfide of greater than 50 parts per million.

Wyoming's Taxation and Revenue Statute exempts flared gas from the state's 6% natural gas extraction severance tax. As a result, operators extracting oil can dispose of natural gas by burning it off free of charge.

The WOGCC requires that well owners/operators apply for authorization for flaring or venting in any other situation. For example, in January 2019, Wyoming regulators allowed an oil and gas firm to flare up to 4 MMcf/day of gas from two wells in the Powder River Basin for up to 3 months while a pipeline is completed.[77] A similar request for flaring was granted by the commission in August 2018. In that case, three proposed wells were located about 14 miles from an existing pipeline network. The commission granted less gas on average per day, but the exemption was allowed for a longer period of time.

In 2018, the WOGCC was faced with an unusual situation when they recognized an increase in flaring in the Wamsutter gas field. BP had begun drilling in new parts of the reservoir and encountered an increase in retrograde condensation. Gas that would condense into a liquid state as production lowers the pressure in the reservoir, is produced as a liquid, but then rapidly vaporizes into a gas during separation at the well site. Some of that gas, in unexpectedly large volumes, was being flared during oil processing and

[76] "Born on the Bayou - New Louisiana Gas Pipeline Capacity Needed from North to Feed Gulf Coast LNG Exports," April 22, 2018
[77] "Wyoming oil and gas regulators approve large flaring allowance as infrastructure is built," January 8, 2019

transportation. The WOGCC allowed BP to continue to flare while it developed technology solutions to reduce the amount of flash gas, requesting instead that the company report on its progress.[78] Beyond such unique situations, Wyoming does not appear to have large, undeveloped oil resources in areas where natural gas gathering could not be easily expanded. Coupled with a relatively strong regulatory framework, the likelihood of increased flaring is considered to be low.

MONTANA

The Montana Department of Environmental Quality (MDEQ) administers the major environmental protection laws, and the Montana Board of Environmental Review (MBER) has the rulemaking authority under various environmental regulatory statutes. MDEQ monitors oil and gas operations throughout Montana. The Montana Board of Oil and Gas Conservation (MBOGC) administers the state's oil and gas conservation laws, promotes conservation, prevents waste in the recovery of resources, and regulates oil and gas exploration and production. MBOGC monitors conservation regulations at oil and gas operations throughout the state.

Natural gas flaring and venting in Montana is governed primarily by state statute, federal law, and the administrative rules of the state. Oil or gas well operators must use air pollution control equipment to control emissions of volatile organic compounds. An operating company may be subject to production limitations if it flares or wastes associated gas. If the average daily gas production is greater than 100 thousand cubic feet (Mcf) of gas, then an operator must submit a justification with detailed analysis to the MBOGC.

The majority of oil production in Montana has come from the Williston Basin, and since 2000, the large majority from development of the unconventional Bakken, Three Forks shale play.[79] Flaring of associated gas is largely confined to this play. Annual flared gas volumes reported to the EIA have ranged from 3,000 to nearly 9,000 MMcf over the past 7 years.

In addition to the Bakken, there are several other emerging unconventional plays in Montana that have seen limited prospecting. The oil-prone Heath play, the gas-prone Cody shale, and the gas-prone Niobrara Shale are several examples. If associated gas is produced from oil reservoirs developed in the Heath, for example, increases in flared gas volumes could occur in the future.

UTAH

The authority for gas flaring and venting regulations in Utah is the Division of Oil, Gas, and Mining at the Department of Natural Resources. Flaring or venting is permitted in very specific circumstances. Up to 1,800 Mcf per month of casinghead gas produced from an oil well may be vented or flared from an individual well without approval. The operator may vent or flare all produced oil well gas only when conducting a stabilized production test. During the month immediately following the initial stabilized

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[78] "Commission weighs next step in gas flaring," September 18, 2018

[79] "Montana's New Energy Frontier – What are the Prospects?," 2012

production test, an operator may vent or flare up to 3,000 Mcf of oil well gas without securing additional approval. Unavoidable short-term oil well gas venting or flaring is allowed without approval under certain circumstances. Major and minor unauthorized flaring or venting incidents must be reported. A minor event is defined as between 50 Mcf and 500 Mcf of gas at any drilling or producing well site, injection or disposal facility; or any transportation, gathering, or processing facility. Utah does not allow gas flaring or venting from gas processing plants except when related to temporary mechanical difficulty or when the gas vented or flared has no commercial value.

There are a number of unconventional oil plays currently being investigated by industry in Utah, including the Uteland Butte limestone in the Uinta Basin and the Cane Creek Shale and the Gothic-Chimney Rock-Hovenweep black shales in the Paradox Basin. The U.S. Geological Survey (USGS) estimated mean undiscovered resources of 214 million barrels of oil, 329 Bcf of associated/dissolved natural gas, and 14 million barrels of natural gas liquids in the Uteland Butte.[80] The USGS also assessed 560 million barrels of undiscovered oil, 12.7 trillion cubic feet (Tcf) of undiscovered natural gas, and 490 million barrels of undiscovered NGL in the entire Paradox Basin (portions in Utah, Colorado, New Mexico, and Arizona).[81] Of this total, the Cane Creek Shale accounted for 215 million barrels, and the Gothic-Chimney Rock-Hovenweep shales accounted for 256 million barrels. The larger portion of the assessment units for these shales lies within Utah state lines.

A shale gas play currently in the early stages of development is the Mancos Shale in central Utah.[82] Several other gas plays that have been tested and show some potential are the Manning Canyon shale in central Utah and the Hermosa Group shales in the Paradox basin.[83] The Potential Gas Committee's 2016 report estimates total "most likely" technically recoverable resource values for the Uinta and Paradox basins to be 50.78 and 4.025 Tcf, respectively.[84] According to EIA, Utah's proven reserves are 318 million barrels of oil and 3.89 Tcf of natural gas (2017).[85, 86] If economics support the further development of these plays, there could be an increase in flaring, at least on a temporary basis, as more wells are drilled and tested.

OKLAHOMA

The Oklahoma Corporation Commission's Division on Oil and Gas regulates drilling, permitting, and waste gas as it pertains to flaring and venting in Chapter 10 of the Oklahoma Register, which went into effect on September 14, 2018.[87, 88] The rules state that wasting oil or gas is prohibited. Exceptions to this rule are found in subsection 3-15 of Chapter 10, which delineates permitting requirements and temporary actions to implement to reduce hazards to human health. Permit applications include estimates of volumes to be flared

[80] USGS, 2015, "Assessment of Undiscovered Oil and Gas Resources in the Uteland Butte Member of the Eocene Green River Formation"

[81] USGS, 2012, "Assessment of Undiscovered Oil and Gas Resources in the Paradox Basin Province, Utah, Colorado, New Mexico, and Arizona"

[82] Utah Geological Survey, 2015, "Tight-Oil and Shale –Gas Plays and Activities in Utah"

[83] "Utah Shale Gas: A developing Resource Play," AAPG Convention, April 20-23, 2008

[84] Potential Gas Committee Report, July 2017

[85] EIA, Crude Oil Reserves Data, 2012-2017

[86] EIA, Natural Gas Reserves Data, 2012-2017

[87] Oklahoma Corporation Commission

[88] Title 165: Oklahoma Corporation Commission Chapter 10: Oil and Gas Conservation

or vented, but the state does not aggregate these estimates, nor collect actual totals.

The Oklahoma Department of Environmental Quality (DEQ) operates both major and minor emissions source permitting programs.[88, 89] Permittees must maintain records of VOCs stored, monthly throughputs, and emissions calculations used to demonstrate compliance, including records of all periods of uncontrolled venting. This regulation requires a 95% VOC destruction efficiency during periods of that flaring or that enclosed combustion devices are operational.[91]

The DEQ has incorporated by reference the New Source Performance Standards (NSPS), which specifically deal with a number of emission unit types located at oil and gas well sites (including storage tanks whose emissions may be controlled by flares). The type of permit required and whether NSPS applies is dependent upon the particular facility's emissions classification. Requirements to operate flares and vapor recovery units may be incorporated into either a major source permit or a minor source permit depending on the particular facility.

Currently, development is centered on a number of unconventional plays that include the Devonian aged Woodford shale, the Caney/Woodford shale, and the Mississippian Springer/Goddard shale (Anadarko), among others.[92] The large majority of horizontal oil and gas well completions are in the Woodford Shale. Lower natural gas prices shifted the focus of the Woodford play toward condensate and oil areas such as the "Cana" (western Canadian County) area in 2007 and the "SCOOP" (South Central Oklahoma Oil Province) area in 2012.

A pipeline to move natural gas from Oklahoma to destinations along the Gulf Coast and southeastern United States received the green light from FERC and $680 million in financing for construction. Plans to build the 200-mile, 36-inch Midship Pipeline are moving forward. Expected to be placed in service by the end of the year, the pipeline is designed to move 1.4 Bcf of natural gas per day from Oklahoma's SCOOP and STACK shale plays to a point just north of the Red River near Bennington, Oklahoma, where it can connect with major interstate pipelines.[93, 94]

KANSAS

n Kansas, natural gas produced from natural gas wells, in connection with the production of oil, or coalbed natural gas produced from coal seams or associated shale, may be flared, vented, or used in any manner as authorized by regulations of the Kansas Corporation Commission (KCC). Pursuant to Section 82-3-208 of the KCC's General Rules and Regulations for the Conservation of Crude Oil and Natural Gas, the venting or flaring of non-sour casinghead gas may be permitted if the operator files an affidavit with the Conservation Division of the Commission ensuring that: (1) the well produces equal to or less than 25 Mcf/day of casinghead gas, (2) marketing the casinghead gas volume is uneconomic due to pipeline or marketing expenses,

89 Oklahoma Statutes
90 Oklahoma Title 252. Department of Environmental Quality, Chapter 100. Air Pollution Control
91 Oklahoma Title 252. Department of Environmental Quality, Chapter 100. Air Pollution Control
92 "Oklahoma Shale Resources Play," Oklahoma Geology Notes, April-June 2017
93 SCOOP and STACK
94 https://www.chron.com/business/energy/article/680-million-pipeline-gets-green-light-to-move-13661263.php

or (3) the operator has made a diligent effort to obtain a market for the gas but failed to do so. Flaring more than 25 Mcf/day of casinghead gas requires that an application be filed with the Conservation Division and it may be approved following the consideration of necessity and compliance with air quality regulations, among other factors. Any volume vented or flared under such conditions must be metered and reported to the KCC semiannually. Additionally, regulations require that all gas venting or flaring activity be carried out to prevent injury or damage to property.

Further, without a hearing, the KCC permits the venting or flaring of natural gas other than casinghead gas if needed for well evaluation or operation for reasons that include well dewatering, testing, and cleaning as well as emergencies. Operators only need to provide notification in these circumstances if the well is to be vented or flared for more than 7 days. In any other conditions not listed in this section, gas may be flared or vented if the operator files an application and the commission approves the application before the operator commences the venting or flaring activity.

The most significant unconventional play currently being developed in Kansas is the Mississippian Limestone (ML), a carbonate that produces primarily oil. The play underlies northern Oklahoma and southern central Kansas and extends a bit into north western Kansas. The first horizontal wells in the ML were drilled in 2007, and drilling rose through 2012, but declined during 2014 along with oil prices. If economics support further development in the future, there may be some increase in flared associated gas volumes.[95]

PENNSYLVANIA

The Pennsylvania Department of Environmental Protection's Bureau of Air Quality is responsible for enforcing the Pennsylvania Air Pollution Control Act,[96] and the Office of Oil and Gas Management oversees compliance with the Oil and Gas Conservation Law.[97] These roles involve reviewing permits, as well as ensuring regulatory compliance through inspecting wells, storage facilities, pipelines, and compressor stations. Although the state processes permits for venting and flaring of natural gas, they do not maintain a database of actual volumes of gas vented or flared.

Unconventional gas wells drilled in the Marcellus or Utica shale plays in Pennsylvania are authorized under Exemption 38 of the Air Quality Permit Exemptions list, which has requirements for flaring activities conducted at unconventional gas wells.[98] Venting of natural gas is authorized as long as the conditions of Exemption 38 are met. GP-5A, entitled *Unconventional Natural Gas Well Site Operations and Remote Pigging Stations*, has additional requirements for well sites that cannot meet conditions of Exemption 38.[99] Venting emissions are counted in the source emission when determining whether

[95] Evens, C. S., and K.D. Newell, 2013, "The Mississippian Limestone Play in Kansas: Oil and Gas in a Complex Geologic Setting," Kansas Geological Survey, Public Information Circular 33

[96] Pennsylvania Department of Environmental Protection, Air Programs

[97] Pennsylvania Conservation Law Background

[98] Pennsylvania Department of Environmental Protection, Bureau of Air Quality, Air Quality Permit Exemptions

[99] Pennsylvania Department of Environmental Protection, "A Pennsylvania Framework of Actions for Methane Reductions From the Oil and Gas Sector"

a control is required to be installed. Specifically, all flaring operations using an open flare, which is only authorized for temporary flaring activities, must be conducted in accordance with the federal requirements in 40 CFR 60.18(b).[100]

All permanent flaring operations must be conducted using an enclosed flare. In addition, the flares must be compliant with 40 CFR Part 60 Subpart OOOO or 40 CFR Part 60 Subpart OOOOa, depending on the date of construction or installation. Federal requirements for flaring conducted at conventional wells include 40 CFR 60.18(b), 40 CFR Part 60 Subpart OOOO, and 40 CFR Part 60 Subpart OOOOa, again depending on the date of construction or installation.

WEST VIRGINIA

The West Virginia Department of Environmental Protection's Division of Air Quality is responsible for enforcing regulations associated with natural gas flaring, and its Office of Oil and Gas enforces oil and gas exploration, drilling, storage, and production more broadly. The state regulations are guided by the West Virginia Code, which requires that oil and gas producers submit a Plan of Operation for the flaring of natural gas and report the purpose of flaring, volume of gas to be flared, and hours per day of flaring. As a stationary source of air pollution, a flare must have a permit before construction and operation. However, a flare can be exempted from the permit requirement if it is used during the maintenance and repair of natural gas pipelines, is temporary (active for less than 30 days cumulatively or on-site for less than 10 days), or results in emissions below certain threshold amounts. While the Division of Air Quality does permit flares and limits the amount of gas that can be flared, it does not maintain a database that tracks the amount of gas flared statewide.

[100] U.S. Environmental Protection Agency, Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced after September 18, 2015: New Source Performance Standards (NSPS)

Category 3 States (States with Little Chance of Increased Flaring)

As shown in Table 6, this group comprises the 19 remaining oil and gas producing states. These states have little to no flaring currently and exhibit few of the characteristics that might indicate a potential for flaring to occur in the future. Compared to Group 2 states, there is very little possibility that a combination of rapid oil play development and regional pipeline capacity constraints could lead to an increase natural gas flaring in these states.

TABLE 6. Category 3 States Relative Flaring and Venting Indicators

State	Gas Flaring	Undeveloped Associated Gas Potential	EPA GHG Emissions Estimate (2012)	EIA 2017 Flared and Vented (MMcf)	EIA 2017 Associated Gas Production (MMcf) *	EIA 2017 Oil Production (MMBbls)
Ohio	Yes	No	High	No	4,169	19
Arkansas	Yes	No	Medium	No	2,486	5
Kentucky	Yes	No	High	No	0	2
Illinois	Yes	No	Low	No	0	8
Indiana	Yes	No	Low	No	0	2
Idaho	Yes	Possibly	Low	No	0	0.1
California	Limited	No	Medium	No	57,820	174
Florida	Limited	No	Low	No	14,852	2
Alabama	Limited	No	Medium	No	9,002	7
Michigan	Limited	No	Medium	No	4,257	5
Mississippi	Limited	Possibly	Low	No	5,522	18
South Dakota	Limited	No	Low	No	297	1
New York	Limited	No	Low	No	123	184
Nebraska	Limited	No	Low	No	48	2
Virginia	Limited	No	Low	No	4	<0.1
Nevada	Limited	No	Low	No	3	0.3
Tennessee	Limited	No	Low	No	0	0.3
Missouri	Limited	No	Low	No	0	0.1
Arizona	Limited	No	Low	No	0	<0.1

*States ranked in order of associated gas production.

IDAHO

The Oil and Gas Division at the Idaho Department of Lands serves as the administrative arm of the Idaho Oil and Gas Conservation Commission, which regulates oil and gas exploration, drilling, and production. The Air Quality Division within the Idaho Department of Environmental Quality assures compliance with federal and state air quality standards by monitoring air quality and collecting data.

After a well is completed and while it is being tested, the owner or operator may flare gas for no more than 14 days without paying royalties and severance taxes on the flared gas. Under no conditions may gas be flared for more than 60 days after a well is completed or recompleted. Prior to flaring gas, owners or operators must notify the county in which the well is located, as well as all owners of occupied structures within one-quarter mile radius of the well. After well testing is complete, no gas may escape into the air, and all gas produced must be utilized without waste.

Temporary flaring is allowed for the purposes of well control safety, safe disposal of waste gases that cannot be processed or sold during drilling and testing of oil and gas wells, and well testing for the purpose of determining potential volumes of hydrocarbons and economic viability. Flaring can also occur during well completion and workover processes. While gases can be vented directly to the air without being burned, the Oil and Gas Division at the Idaho Department of Lands does not consider venting a safe, acceptable alternative to flaring and advises that if gas volumes are sufficient to sustain stable combustion, then the gases should be burned.

Relatively recent oil and natural gas production in Idaho is currently underway in the Payette Basin (Payette and Gem Counties) along the southwestern border.[101] A total of 17 exploration wells have been drilled there since 2010, and 8 of these are currently producing natural gas and condensate.[102] The two new fields in this play are named Willow and Hamilton. So far, no wells have produced hydrocarbons in southern or southeastern parts of the state, but exploration is ongoing.[103]

KENTUCKY

Flaring and venting are allowed in Kentucky, as long as operators are in compliance with applicable rules and regulations. Kentucky does not have unconventional plays, where high volume hydraulic fracturing is carried out and where flaring large amounts of natural gas during the production of natural gas liquids and oil is required. According to the Kentucky Division for Air Quality, most wells, if any, that may flare would be extremely small and below the threshold for requiring any type of air permit or air registration from the Kentucky Department for Environmental Protection (DEP).

Kentucky Revised Statutes Chapter 353, Mineral Conservation and Development, addresses venting and flaring regulations. Flaring of natural gas in

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101 Idaho Geological Survey, Oil and Gas Conservation Commission

102 OGI, February 6, 2017, "Idaho enters ranks of hydrocarbon producing states"

103 Ibid

conjunction with crude oil production is permitted. The rules stipulate that natural gas may not be wasted or permitted to escape from any well or pipeline when prevention is reasonably possible. In situations where venting or flaring is necessary, the owner or operator must use all reasonable diligence to minimize waste to the extent possible. Additionally, regulations prohibit well operators from wasting oil or gas while locating, drilling, equipping, operating, or producing any oil or gas well, including the unnecessary or excessive loss of oil and gas by spillage, venting, or destruction.

There is a small possibility that if the New Albany Shale becomes economic to develop, there may be a small increase in the volume of gas flared over time.

OHIO

The Division of Oil and Gas Resources at the Ohio Department of Natural Resources is charged with enforcing the rules related to natural gas flaring and venting in the state. The regulations require that well owners and operators prevent wasting oil and gas but allows for flaring gas *"when it is necessary to protect the health and safety of the public or when the gas is lawfully produced and there is no economic market at the well for escaping gas."*[104] Additional relevant rules mandate that "*All gas vented to the atmosphere must be flared, with the exception of gas released by a properly functioning relief device and gas released by controlled venting for testing, blowing down and cleaning out wells.*"[105]

In addition, the Ohio Environmental Protection Agency (EPA) is tasked with administering air quality permitting programs in Ohio. All oil and gas production facilities are required to obtain an air permits before beginning construction. Facilities need to consider the flare size to apply for the appropriate permit. According to the Ohio EPA, once facilities are permitted, the actual volumes are not collected and aggregated.

Continued development of the Utica and Point Pleasant formations in eastern Ohio could lead to continued instances of flaring related to well testing and production facility operation. However, as this play is fundamentally a gas play with associated condensate, there is very little chance that large volumes of gas would be flared.

ARKANSAS

In general, wasting oil and gas is prohibited in the State of Arkansas, as stated in the relevant Arkansas Code, Title 15, Natural Resources and Economic Development, Section 15-72-105, entitled, "Prohibition on Wasting Oil or Gas." In this statute, gas is defined as all-natural gas, including casinghead gas, and all other hydrocarbons. The regulations of the Arkansas Oil and Gas Commission, however, allow operators to vent or flare gas within 7 days of when gas is first encountered in a well. After 7 days,

[104] Ohio Revised Code, Title 15, Section 1509-20

[105] Ohio Administrative Code 1501:9, Chapter 1501:09-9 Safety Regulations, 1501:9-9-05, Producing Operations

gas may only be vented or flared if the operator has successfully obtained an exception from the Arkansas Oil and Gas Commission.

Active Arkansas plays include the Fayetteville Shale in the Arkoma Basin and the Brown Dense Shale in southern Arkansas. One of the first U.S. shale plays to be developed, the Fayetteville Shale, is a dry natural gas formation that is estimated to hold between 14 Tcf and 20 Tcf of technically recoverable natural gas. Production peaked between 2012 and 2014 and has since declined. Another unconventional play is the Lower Smackover/Brown Dense shale (BDS), an oil and gas play underlying part of southern Arkansas. The BDS remains an emerging play, despite testing with more than a dozen wells since 2012, most of which were located in northern Louisiana rather than Arkansas. Significant pressure to increase flaring of associated gas in Arkansas is unlikely.

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ILLINOIS

The Illinois Department of Natural Resources (DNR) regulates the oil and gas industry. The DNR's Office of Oil and Gas Resource Management is the regulatory authority in Illinois for oil and gas operations. The Illinois Oil and Gas Act stipulates guidelines for the conservation of oil and gas resources, regulation of drilling, construction, operation, and plugging of oil and gas production wells; operation and maintenance of oil production facilities; and handling, transportation, and disposal of oilfield wastes.

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106 EIA/BEG, 2013, "Shale Gas Plays," EIA Energy Conference, June 2015,

The Hydraulic Fracturing Regulatory Act applies to all wells in which high-volume, horizontal hydraulic fracturing operations take place in Illinois.

The Oil and Gas Act prohibits unnecessary or excessive surface loss or destruction of oil or gas resulting from evaporation, seepage, leakage, or fire into the open air in excessive or unreasonable amounts. The Act also states, *"it shall not be unlawful for the operator or owner of any well producing both oil and gas to burn such gas in flares when such gas is lawfully produced, and where there is no market at the well for such escaping gas."*

The Hydraulic Fracturing Regulatory Act requires drilling permit holders to minimize the emissions associated with venting of hydrocarbon fluids and natural gas during the production phase and to safely maximize resource recovery and minimize releases to the environment. This regulation also mandates that, in situations when it is technically infeasible or economically unreasonable to minimize emissions associated with the venting of hydrocarbon fluids and natural gas during production, the operator must flare any natural gas produced during the production phase. All flares are required to operate with a combustion efficiency of at least 98%.

Flare permit holders must record the amount of gas flared or vented from each high volume horizontal hydraulic fracturing well or storage tank on a weekly basis and report the total amount of gas flared or vented from each well during the previous 12 months. Uncontrolled emissions exceeding 6 tons per year from storage tanks containing natural gas or hydrocarbon fluids must be recovered and routed to a flare.

Historically, Illinois oil and gas production is limited to the southern half of the state and is mostly concentrated in the southeastern corner. The New Albany shale is an unconventional gas play that has been well studied and tested in southern Indiana and Kentucky. However, to date, only the Russellville field, in eastern Lawrence Co. has established commercial production in the New Albany in Illinois. In 2017, Illinois regulators approved the first permit to allow high-volume hydraulic fracturing in a well targeting the New Albany Shale. However, the New Albany, should it become economic to develop, is primarily a gas play. There are no unconventional oil plays with associated gas that might require flaring in Illinois.

INDIANA

Pursuant to Indiana Code, Title 14, Natural and Cultural Resources, waste of oil and gas resources is prohibited, except when an operator of a well producing both oil and natural gas may burn the natural gas *"in flares located a safe distance from the well by an owner or operator of a well producing both oil and natural gas if it is not economical to market the natural gas."*

More than 500 small fields exist in southwestern Indiana, and small flares are associated with marginal oil wells. The New Albany shale is an unconventional gas play that has been well studied and tested in southern Indiana and Kentucky. However, the play remains emerging in the region, and Indiana has not seen evidence of commercial production.

ALABAMA

The State Oil and Gas Board of Alabama (OGB), which is part of the Geological Survey of Alabama, is a regulatory agency mandated with preventing waste and promoting the conservation of oil and gas. The OGB has the authority to promulgate and enforce rules and regulations to achieve this mission and has done so in the State Oil and Gas Board of Alabama Administrative Code. Within this code, Rules 400-1 through 400-7 relate to the flaring and venting of natural gas.

Additionally, Alabama Statute Title 09, Conservation and Natural Resources, Chapter 17, Oil and Gas, Section 9-17-11, states that waste of oil or gas is prohibited. Rule 400-3, Coalbed Methane Gas Operations, Section 400-3-5-.03, Venting or Flaring of Coalbed Methane Gas, indicates that venting or flaring of gas from a permitted coalbed methane gas well is allowed where necessary for safety reasons or for the efficient testing and operation of coalbed methane gas wells.

The largest concentration of flares in Alabama likely comes from flaring related to the production of low-pressure natural gas from coalbed methane wells in the Black Warrior Basin of northwestern Alabama. But these are not likely to be large flares, nor would the volume of gas flared be expected to be high. Leaks of gas from coalbed methane well infrastructure are most likely the major contributor to methane venting in Alabama.

There are no significant known undeveloped oil resources in Alabama, where associated gas flaring could occur to any significant degree in the future.

CALIFORNIA

California has historic precedent for not allowing the release of natural gas dating back to 1939, when the state enacted statues entitled, *Wasting of Natural Gas*, as part of Chapter 2, section 3500-3503 of the Public Resources Code. This regulation restricts flaring and venting implicitly with the statement that, *"All persons, firms, corporations, and associations are prohibited from willfully permitting natural gas wastefully to escape into the atmosphere*" (Chapter 2, section 3500). Section 3502 explains that this regulation is classified as a misdemeanor infraction punishable by fine or imprisonment, and section 3500 provides that each day that natural gas is wasted is considered a separate violation.[107]

Adopted in March 2017, as part of the California Code of Regulations, the *Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities* regulation (Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13) is designed to reduce methane emissions.[108] Under this rule, oil and gas facilities on private, state, and federal land and offshore property are required to limit vented gas, as well as unintentional leaked or fugitive emissions. Tribal land is the one property exemption. In cooperation with the local air districts, the enforcing entity is the California Air Resources Board (CARB), which is tasked with protecting the public from air pollution and developing programs and actions to address climate change.

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[107] California Department of Conservation, Oil, Gas & Geothermal Resources, Statutes & Regulations, January 2019

[108] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13

California is divided into local air districts that are primarily responsible for controlling air pollution from stationary sources.[109] Many air districts with significant oil and gas production have rules that have been in place for decades and designed to reduce criteria pollutant emissions from the oil and gas sector.[110] According to CARB, the air district rules control emissions of VOCs, but some methane reductions are achieved as a co-benefit since both VOCs and methane are found in field gas in oil and gas operations. In general, district rules prevent uncontrolled venting of produced field gas. In addition, district rules limit combustion pollutants from flaring. The *Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities* regulation was intended to build upon existing district rules by covering methane-specific sources not already controlled by the districts.

The *Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities* regulation includes provisions that aim to reduce fugitive and vented emissions of methane from both new and existing oil and gas facilities by enforcing standards for separator and tank systems; circulation tanks for well stimulations; leak detection and repair; underground natural gas storage monitoring; natural gas compressors; and pneumatic devices and pumps.[111] Implementation is dependent upon both CARB and the local air districts, with most districts responsible for enforcement, as outlined in individual Memoranda of Agreements.[112] The timeline for implementation spans over 2 years and includes deadlines for planning, testing, upgraded equipment installation, and reporting.[113]

California oil production has been declining since 1985 and relies on steam flooding to produce much of the regions heavy oil. Relatively small volumes of associated gas and even smaller amounts of non-associated gas are produced.[114] The Monterey Shale is considered to be both a conventional and unconventional formation, depending on location and rock characteristics, with primarily crude oil production potential at depths between 8,000 and 14,000 feet. In 2014, EIA downgraded previous optimistic estimates of recoverable oil from the Monterey to a total of 600 million barrels from all areas.[115] However, efforts to find a way to commercially solve its geological and well performance challenges have been unsuccessful. It is unlikely that California will witness any significant increase in natural gas flaring or venting in the foreseeable future.

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109 California Air Resources Board, California Air District Map for District Rules, March 23, 2012

110 California Air Resources Board, District Rules Database, March 6, 2019

111 California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13

112 California Air Resources Board, Oil and Gas Memoranda of Agreements

113 California Air Resources Board, Oil and Natural Gas Production, Processing, and Storage

114 California Department of Conservation, "2017 Report of California Oil and Gas Statistics," May 21, 2014

115 Reuters, "U.S. EIA cuts recoverable Monterey shale oil estimate by 96 percent," May 21, 2014

OTHER STATES

The states of **Michigan**, **Mississippi**, **Florida**, **Missouri**, **Nebraska**, **Nevada**, **New York**, **South Dakota**, **Tennessee**, **Virginia**, and **Arizona** all exhibit a very limited amount of natural gas flaring, a very small likelihood of future development of oil resources with significant associated gas requiring flaring, relatively low indications of methane emissions according to the EPA GHG emissions estimates, no reported flaring to EIA, zero or negligible associated gas production, and with the exception of New York, extremely low volumes of oil production. While flaring and venting certainly takes place within these states, the volumes are very low, and the chances of any increase are negligible.

PROJECTED ASSOCIATED GAS PRODUCTION

One of the important, perhaps the most important, drivers of flaring is the development of oil plays with significant volumes of associated gas that does not have a nearby market or an infrastructure to connect it to a market. This has been the case in parts of Texas and North Dakota.

IHS Markit has published a projection of associated natural gas production to 2050.[116] This projection identifies several important findings:

- West Texas Intermediate (WTI) crude oil prices are assumed to remain at about $63/barrel in real terms through 2030. The subsequent growth in drilling programs means that the momentum in oil production in the Permian Basin should remain strong; and, consequently, associated gas production is expected to continue its upward trajectory.
- Associated gas will grow on the strength of oil prices and new takeaway capacity; it is expected to increase by 13.6 Bcf/day, to 39.4 Bcf/day in 2030—representing 38% of U.S. Lower-48 production, up from a share of 26% in 2018. The primary sources of growth are the Permian Basin, SCOOP, STACK, and Wattenberg areas.
- Permian Basin production is expected to grow by 3.4 Bcf/day between 2018 and 2020 and by another 8.8 Bcf/day through 2030, pushing production to 21.3 Bcf/day in 2030. With low-cost operations, an inventory of drilled-but-uncompleted oil wells, and new takeaway oil and gas pipeline capacity coming online over the 5 five years, the Permian Basin will be one of the defining areas for U.S. Lower-48 production for this decade.
- Approximately 14.5 Bcf/day of new gas pipeline takeaway capacity is proposed to alleviate gas constraints from the Permian Basin. IHS expects that 8.0 Bcf/day of gas pipeline capacity will need to be built over the next 5 years.
- Beyond the Permian Basin, the next tranche of associated gas production growth will come from the SCOOP/STACK, Denver-Julesberg Niobrara, Bakken, and Eagle Ford plays. Together, these areas will account for 5.6 Bcf/day of the increase in production from 2021 to 2030.
- Following significant growth during the 2020s, total associated gas production will reach a peak in 2035, at 40.5 Bcf/day, and then drop to 37.7 Bcf/day in 2040.

Continued development of these oil plays will require flaring from well testing and production operations, even if the expected pipeline additions reduce the need for large amounts of flaring of associated gas. The expectation is that there will be continued need for some degree of associated gas flaring in all of these plays for the next two decades.

[116] IHS Markit, 2019, "North American Natural Gas Long-Term Outlook," February 28, 2019, accessed via NETL subscription

TECHNOLOGY SOLUTIONS TO REDUCE ASSOCIATED NATURAL GAS FLARING AND VENTING

Commercial or pre-commercial technologies exist for capturing gas that would otherwise be flared and converting it into usable or marketable products. These fall under the seven main categories listed below. A few examples of available technologies are included below as well.

1. **Compressing natural gas (CNG) and trucking it short distances for use as a fuel for oil field activities** – Gas can be compressed at the well pad and trucked to a gas processing plant or to a location where it can be used as a fuel. This approach may be feasible at wells relatively close to a processing plant or other point where gas can be put into the pipeline system (20–25 miles or less). EPA looked at the feasibility of trucking CNG in Western North Dakota and determined that at least 89% of flared gas in one area could be economically captured this way.[117]
   - *GE* and *Ferus NGF* have tested a system for Statoil in the Bakken Shale that they call the "*Last Mile Fueling Solution*" because it takes the gas the final distance, or the last mile, from the point of supply at the wellhead to the point of use without the need for pipes on the ground. It combines GE's *CNG in a Box* technology with Ferus's oil field logistics to deliver CNG for powering rigs, truck fleets, electric generators, and other equipment.[118]
   - *Certarus* offers a portable CNG compression and transport solution. This technology is designed primarily as a CNG supply solution, using portable CNG tanks to deliver gas to end users when pipeline transport is not possible. A portable gas compression unit could be utilized to compress gas that would otherwise be flared and store it in a portable container for transport and use elsewhere in the operating area. Footprint is 45 feet x 20 feet.[119] **Extracting NGLs for the flare gas stream before flaring the remaining methane (a partial solution)** – NGLs can be removed from associated gas using mobile equipment on well pads and trucked away for sale. Such systems work best with rich associated gas streams. The residue dry gas remaining after NGL recovery can be captured with CNG trucking or used for power generation. Commercial systems that can capture C5 and heavier hydrocarbons are simple and inexpensive, but only reduce flaring a limited amount. Technologies that also capture C3 and C4 capture a larger portion of the input gas and result in less flaring but require a larger initial investment. Higher rates of flare reduction can be achieved by coupling NGL recovery with other technologies.

- *Pioneer Energy's Flarecatcher*™ mobile associated gas processing plants in sizes from 400 to 5,000+ Mcf/day that extracts NGLs from raw associated gas and delivers

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[117] Clean Air Task Force, "Putting Out the Fire: Proven Technologies to Improve Utilization of Associated Gas from Tight Oil Formations," November 17, 2015

[118] Bakken, "Taming North Dakota's Gas Flares," September 10,

[119] Certarus website, https://certarus.com/portable_hubs.php

dry gas for use in power generation or conversion to CNG or LNG. Pioneer Energy's *Vaporcatcher*™ oil tank battery vapor capture systems scaled to 400 Mcf/day process storage tank vapors to separate produced NGLs into commercial propane, LPG, and natural gas condensates.[120]

- *GTUIT's* modular system uses mechanical refrigeration and compression to achieve NGL recovery.[121]

2. **Converting the gas to electric power using small-scale generators** – A variety of technologies are available for local power generation, including reciprocating engines and gas turbines. Local load systems work best when using lean associated gas (e.g., the residual gas after NGL recovery).
   - Capstone Turbines offers portable gas-fueled micro-turbine generators for gas-to-power solution. The smallest units are 30kW (operates on 10 Mcfd of 1MMBtu/Mcf gas at ~60 psi) and 65kW (operates on 20 Mcfd). The 30kW unit's dimensions are 30 x 60 x 71 inches. The largest Capstone micro-turbine is 1000 kW (operates on 264 Mcfd).
   - *Alphabet Energy's* thermoelectric combustor that converts heat from flared gas into electric power.[123]
   - *CompAp* has developed a bi-fuel system for combining natural gas and diesel to generate power using flare gas.[124]
   - *Gulf Coast Green Energy* and *ElectraTherm* partnered with the HESS Corp. to test the *ElectraTherm Power+ Generator*™, a distributed waste-heat-to-power technology, at a North Dakota oil well to reduce oil and gas flaring. The project captures the natural gas that would otherwise be flared to generate emission-free electricity.[125]

3. **Small-scale, gas-to-methanol or gas-to-liquids conversion plants** – Systems have been developed to convert natural gas to chemicals or fuels on site. These systems have not been applied to many U.S. flaring situations to date.
   - *GasTechno*® systems for producing methanol or gas-to-liquids products (e.g., high-grade diesel fuel).[126]
   - *Primus Green Energy's* modular systems for conversion of flare gas into methanol or fuels.[127]
   - *CompactGTL's* small-scale, modular gas-to-liquids technology.[128]
   - *Calvert Energy's* small-scale gas-to-liquids solution can convert natural gas into high cetane, zero sulfur diesel. The target market is the subset of large flares where associated gas is being flared while waiting on pipeline infrastructure. The Calvert technology converts 1MMscfd of natural gas into 100 barrels per day of syn-diesel. The footprint for a 100 bpd plant is about 4 meters long x 3 meters wide x 5 meters high.[129]

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120 Pioneer Energy, Products, Mobile Flare Gas Capture Solutions & Modular Gas Processing Plants
121 GTUIT, Gas Capture System Dramatically Cuts Emissions
122 Capstone website, https://www.capstoneturbine.com/
123 Alphabet Energy, E1 Thermoelectric Generator
124 ComAp, Power Generation from Flared Gas
125 GulfCoast Green Energy, Flare Gas to Power
126 GasTechno, GasTechno Flare Gas Recovery
127 Primus Green Energy, Commercial Applications, Flared Associated Gas
128 CompactGTL, Small scale, modular Gas-to-liquids (GTL) technology
129 Calvert website, http://calvertenergy.eu/index.html

4. **Converting captured gas to LNG and trucking it short distances for use as a fuel for oil field activities** – Gas can also be liquefied and trucked to a location where it can be used as a fuel. This may be appropriate when the gas does not require a large amount of conditioning.
5. *Galileo Technologies*, in partnership with *SPATCO Energy Solutions*, supplied such a solution for Terra Energy in the Bakken Shale play to integrate flare gas capture and LNG production right at the wellhead.[130] **Utilizing gas that would otherwise be flared for beneficial use at the well pad**
    - *Heartland Water Technology* offers a system that utilized gas at the wellsite to evaporate produced water, producing a concentrated brine or solid salt waste stream for disposal, the volume of which is significantly less volume than the produced fluid volume.[131]
6. **Improving the efficiency of existing flare reduction technologies to further reduce flare volumes**
    - *EcoVapor Recovery Systems LLC* offers a technology for capturing condensate tank vapors that are not captured by existing vapor recovery units and that include oxygen, and using a proprietary catalytic system to recover the gas for sale.[132]

While many of these technology solutions have been tested and found to work, they have not all been widely applied. The problem is not a failure of technology but rather a failure of economics. The capital cost of installation (or the rental cost), plus the costs of operation, do not appear to justify widespread application of these solutions. Contributing factors may also include the following:

- Ease and familiarity of operators with flaring relative to alternatives
- Fact that producers do not want to be in the business of collecting, transporting, and selling chemicals, fuels, CNG, or LNG
- Gas composition issues that make some technologies less profitable or harder to apply
- Legal or royalty issues related to the conversion and sale of gas into other products
- Lack of familiarity with regulations that might apply to these methods
- Lack of familiarity with the technology and the need to avoid hiring or training additional staff.

[130] Galileo Technologies, Distributed LNG Production: Galileo's flare reduction solution for Bakken
[131] Heartland Water Technology website, https://www.heartlandtech.com/
[132] EcoVapor website, https://www.ecovaporrs.com/

DOE INITIATIVES TO ACCELERATE TECHNOLOGY SOLUTIONS TO REDUCE NATURAL GAS FLARING AND VENTING

In response to the Administration's FY19 Budget Request and House/Senate FY19 appropriations, DOE is preparing a funding opportunity announcement (FOA) for release in 2019 to solicit research proposals focused on mitigating emissions from midstream natural gas infrastructure.

One of the areas of interest is specifically focused on accelerating the development of technologies capable of converting gas that would otherwise be flared into transportable, value-added products. It is envisioned that successful technologies developed in this research and development effort will be integrated into small-scale modular systems that, in the future, can be transported from one flare site to the next for use during periods when natural gas gathering and sales systems are not yet functional.

The FOA will target two areas where basic research needs have been identified: (1) multifunctional catalysts and (2) modular conversion equipment designs.

Multi-Functional Catalysts: One area where research is needed is the early-stage development and evaluation of multifunctional catalysts for the direct conversion of methane to liquid petrochemicals (e.g., methanol, ethanol, ethylene glycol, acetic acid, C3 and C4 analogs, C4+ olefins, and Benzene, Toluene, Xylene) that can be easily transported and are suitable for subsequent conversion into commercial products. Research in this area will focus on methods for process intensification at the nano- to micro-scale and on facilitating high catalyst activity, product yield, selectivity, and mass/heat transfer rates.

Modular Equipment Design Concepts for Conversion to High-Value Carbon Products: Another area of interest is the development of novel equipment and process design concepts for achieving high-selectivity pyrolysis, which is integral to the manufacture of high-value carbon products (e.g., carbon nano- or micro-fibers, carbon nano-tubes, and graphene sheets) from methane or the mixtures of methane, ethane, propane, and butanes representative of natural gas streams being flared. Research in this area will focus on the application of process intensification at modular-equipment scales suitable for deployment and transport between remote locations where gas is being flared.

Of particular interest are approaches that:

- Result in modular, compact, integrated, and transportable technologies
- Have a large turndown ratio and can operate continuously under varying feed rates and compositions
- Have the potential to convert a higher fraction of an associated gas stream, lessening the requirements for NGL recovery
- Can make use of oxygen in the air directly without the need for a separate air fractionation unit, or can make direct use of a weak oxidant, such as CO_2, which may be more readily available—in the case of direct conversion technologies that require oxygen (e.g., partial oxidation of methane to methanol, oxidative coupling of methane)
- Can make use of excess hydrogen in methane to offset energy requirements of the conversion process

- Initially target high-value, small-volume product markets but can pivot toward commodity markets as the technology develops and matures
- Result in technology platforms capable of producing a variety of products using the same or similar materials, equipment, or processes.

DOE's objective is to accelerate the development of modular conversion technologies that, when coupled with the currently commercial alternatives outlines in the previous section, will provide a complete portfolio of options for companies seeking to monetize flared gas volumes of practically any magnitude and at any location.

CONCLUSIONS

All of the states where oil and natural gas are produced have regulatory frameworks in place to prevent waste of these natural resources during their production. Flaring of natural gas is recognized as being necessary for the safe and efficient production, processing, and transportation of both oil and natural gas, and state agencies exist to enforce regulations that require flares to be permitted, set limits on volumes flared, set limits on emissions in general, and specify where flares must be located and how they must be operated.

Some, but not a majority of, states require the reporting of measured or estimated flared volumes. In most cases these volumes are reported voluntarily to the EIA. These estimates are reported for the states with the majority of flared gas volumes, Texas and North Dakota, as well as others. But recent independent assessments based on satellite images have claimed that operators are underreporting the true volume of flared gas.

While states have regulations that require flares to be permitted, they also have rules allowing for regulatory exceptions, as well as mechanisms for operators to obtain permission to flare relatively large volumes of natural gas for long periods of time due to a lack of available pipeline infrastructure or capacity. In Texas and North Dakota in particular, and in the Permian Basin and Bakken plays respectively, the states' interest in facilitating oil production has led to large amounts of associated natural gas being legally flared.

In both of these plays, pipeline and gas processing expansions already underway are likely to fill the gaps in infrastructure over the next 2–5 years, even if additional drilling adds to the volumes of associated gas being produced. In the meantime, states are unlikely to significantly restrict oil production in order to eliminate flaring of associated gas. This approach does not make economic sense in states where significant benefits accrue through oil production taxes and state royalties and where oil and natural gas producers are major employers.

While there are commercial technologies available for capturing and monetizing gas that would be flared, companies have not universally embraced these options for reasons that include: (1) the value of the gas and/or gas liquids captured do not offset the capital and operating costs of the technologies; (2) company management believes that the problem will be resolved through infrastructure expansion and the investment in capture and utilization technology will quickly become obsolete; and (3) legal, regulated flaring is the least risky option and does not require learning how to apply new technologies or modifying existing contracts and operating practices.

The ideal pursuit of flaring reduction include technologies that are inexpensive to build and operate, modular and capable of being moved from well pad to well pad, does not require a gathering system, and are capable of turning a range of gas flow rates and compositions into products that have value on site or at a nearby market center. DOE is launching a research program with the objective of accelerating the development of such technologies in 2019.

APPENDIX A: ANALYSIS OF TEXAS RAILROAD COMMISSION FLARE DATA

A download of Texas Railroad Commission (TRRC) flaring data was acquired, and all of the data for permitted flares for years 2010, 2012, 2014, and 2017 were extracted.[133] These data included monthly permitted flare volumes and volumes of gas actually flared for distinct flares. A frequency distribution of flare sizes for each of those years was subsequently created (see Table A1 and Figure A1).

TABLE A1. Distribution of the Number of Permitted Flares Binned by Flare Volume (Mcf/day) for 4 Years

	Count of Permitted Flares by Volume of Gas Flared			
Volume (Mcf/Day)	2010	2012	2014	2017
0-20	24,146	27,137	29,018	31,295
20-40	14,471	15,016	14,762	13,683
40-60	9,547	9,643	9,549	8,882
60-80	7,180	7,295	7,137	6,598
80-100	5,725	5,683	5,541	5,100
100-120	4,546	4,422	4,255	3,954
120-140	3,711	3,701	3,356	3,302
140-160	3,026	2,802	2,757	2,573
160-180	2,603	2,412	2,268	2,135
180-200	2,164	2,058	1,896	1,806
200-220	1,821	1,693	1,710	1,558
220-240	1,669	1,464	1,422	1,419
240-260	1,423	1,226	1,273	1,221
260-280	1,229	1,137	1,121	1,079
280-300	1,136	1,005	1,006	971
300-320	912	902	883	801
320-340	832	794	827	708
340-360	805	762	768	721
360-380	695	643	681	585
380-400	692	677	589	575
400+	10,772	11,126	11,078	7,663
Totals	99,105	101,598	101,897	96,629

133 https://www.rrc.state.tx.us/about-us/resource-center/research/data-sets-available-for-purchase/production-data/

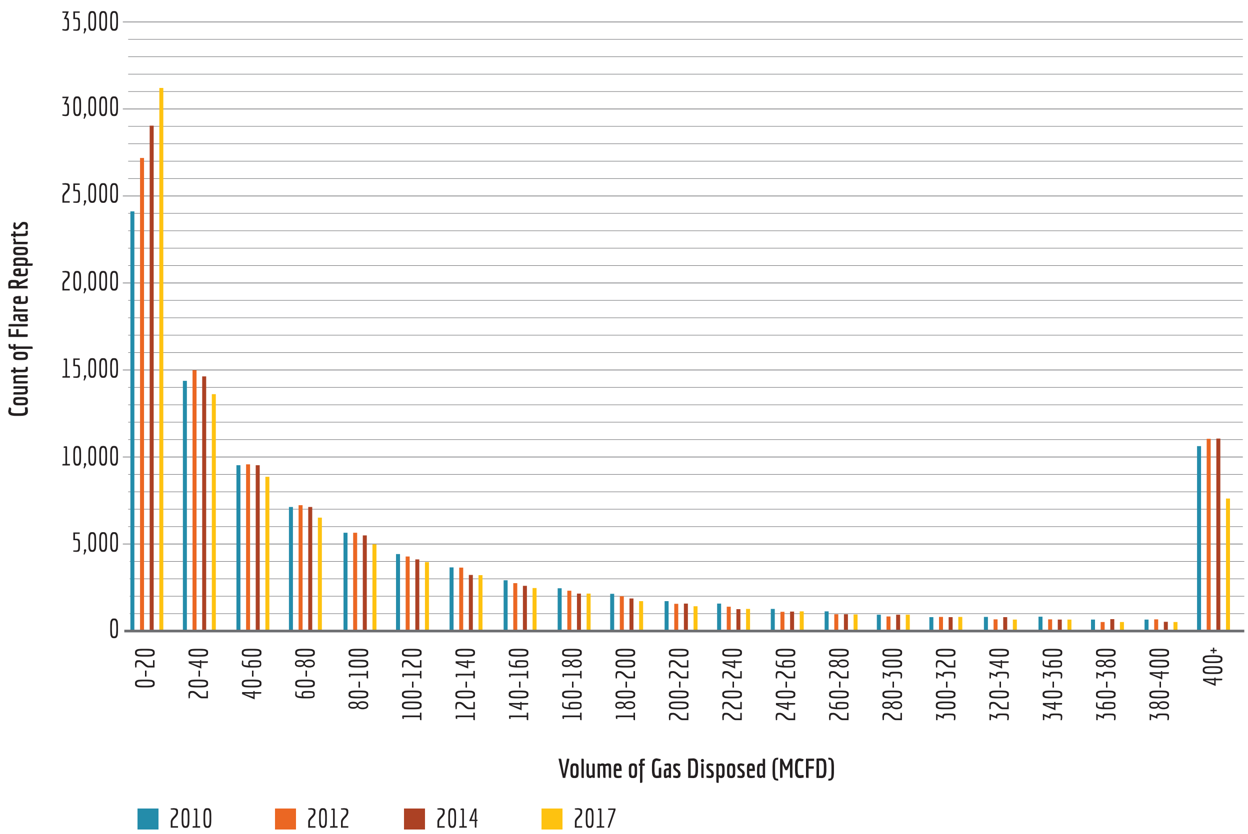

FIGURE A1. Plot of frequency distribution of number of flares binned by flared gas volume in Mcf/day.

The large number of flares identified by this data set seemed inordinately high, especially in comparison to the number of Texas flares identified by the NOAA satellite survey (~2,000 versus ~100,000) as detailed in Figure 12. However, it is reasonable to suspect that only the larger flares are detected by satellite and many smaller flares are invisible to that approach. As well, many of the permitted flares, especially the smaller volume flares, are ephemeral; for example, a flare permitted for a drilling operation in a specific well that is only used infrequently over a several week period over a year. These two sets of numbers may be reconcilable.

This distribution shows that, in 2017, about a third of the flares burn less than 20 Mcf/day, about half of the flares burn less than 50 Mcf/day, and less than 10% burn more than 400 Mcf/day. The roughly 8,000 flares burning 400 Mcf/day, or more were responsible for more than half of all the gas flared in 2017. Between 2010 and 2014, the number of flares and volume flared was fairly consistent. Between 2014 and 2017, the number of flares and volume of gas flared dropped about 5% and 20%, respectively, according to the data reported to TRRC. The share of flares burning less than 20 Mcf/day increased consistently between 2010 and 2017.

The analysis also attempted to determine the spatial distribution of the flares across the state, with respect to the major oil plays currently under development. The TRRC data does not always include location data (coordinates) but does include some county data. The data sets are fairly inconsistent with how the data is reported, and some fields are just left blank at times, which is assumed to be human error.

The TRRC data set was correlated with a drilling info data set using lease numbers to refine the location data. This combined data set was then used to determine county locations for the permitted flares. During this last step, there were about 6,000 data points that did not have accurate location data (or any at all in some cases). Therefore, the county data set (flares with location identified) had approximately 90,000 data points, while the total data set has about 96,000 data points (for 2017 Total Disposed Gas).

Given this caveat, approximately 90,000 flares in 2017 were sorted by county (Table A2). It was determined from this data set that:

- Of the 254 counties in Texas, 200 have permitted flares operating.
- In 2017, there were roughly 97,000 flares in Texas.
- Within the 22 counties that make up the Permian Basin, there were about 6,000 flares, which accounted for about 12% of the gas flared in 2017.
- The 26 counties that encompass the Eagle Ford play had 15,423 flares and accounted for 35% of the gas flared in 2017.
- The other 19 counties across the state having more than 1000 flares each, accounted for a total of 47,553 flares and nearly 40% of the gas flared in 2017.

Figure A2 provides a map of where the flares are located relative to the gas production volumes for individual counties across the state. As would be expected, they align fairly well. A large number of larger flares are located in the western Permian Basin play, along the Eagle Ford play in south central Texas, across the Barnett shale play in the Fort Worth Basin, and where the western portion of the Anadarko Basin extends into the Texas Panhandle.

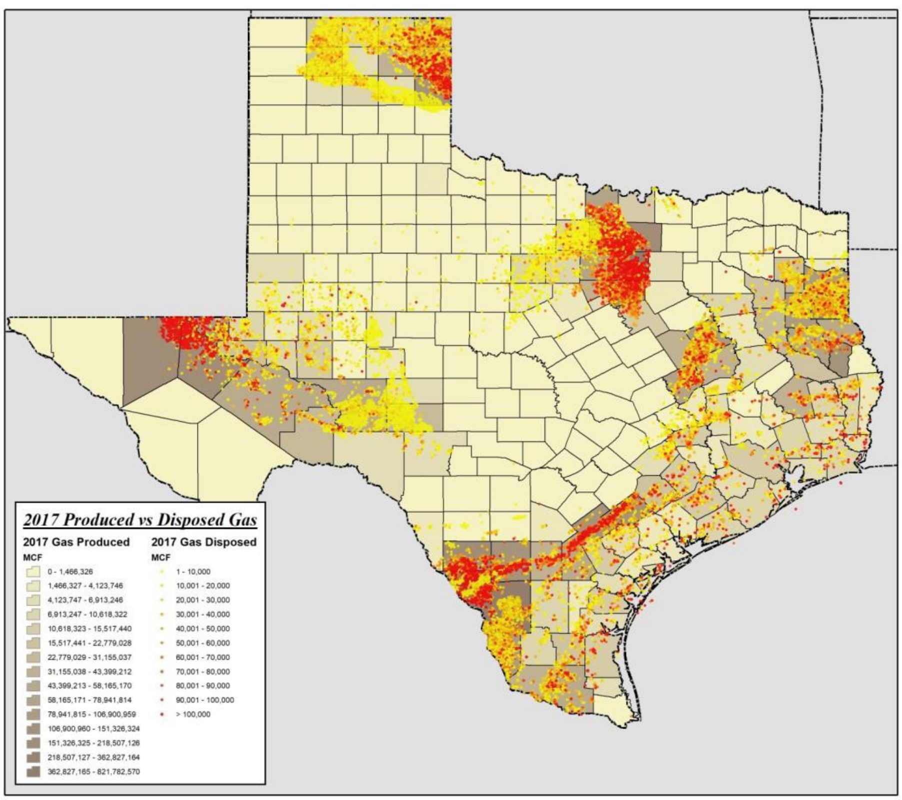

FIGURE A2. Map of Texas TRRC data showing location of flares and with the volume of gas flared during 2017, which is indicated by color; darker red means larger flare. The volume of gas produced, by county, is indicated by color also; darker brown means higher production volume. Source: Texas Railroad Commission

TABLE A2. Distribution of Flares and Flared Volumes by County in Texas for 2017 (Colors indicate plays and high flare count counties, see bottom of table)

County	Count of 2017 Total Gas Disposed	Sum of 2017 Total Gas Disposed (Mcf)	Daily Average 2017 Total Gas Disposed (Mcf/day)
Anderson	80	1,465,589	4,015
Andrews	186	3,811,477	10,442
Angelina	41	756,245	2,072
Aransas	50	5,392,173	14,773
Archer	18	79,508	218
Atascosa	77	2,576,963	7,060
Austin	93	2,478,303	6,790
Bandera	1	11,972	33
Bastrop	59	53,401	146
Bee	384	12,054,361	33,026
Bexar	2	0	0
Borden	5	511	1
Bosque	4	0	0
Bowie	1	19,026	52
Brazoria	136	8,103,585	22,202
Brazos	115	2,986,059	8,181
Brooks	401	18,078,614	49,530
Brown	49	49,201	135
Burleson	115	1,088,346	2,982
Calhoun	54	2,126,245	5,825
Callahan	22	135,412	371
Cameron	3	86,705	238
Camp	3	433,454	1,188
Carson	404	5,899,596	16,163
Cass	35	208,704	572
Chambers	34	4,892,661	13,405
Cherokee	302	4,597,453	12,596
Clay	47	310,683	851
Cochran	3	0	0
Coke	1	0	0
Coleman	14	22,705	62
Collingsworth	302	890,969	2,441
Colorado	242	14,178,380	38,845

County	Count of 2017 Total Gas Disposed	Sum of 2017 Total Gas Disposed (Mcf)	Daily Average 2017 Total Gas Disposed (Mcf/day)
Comanche	31	85,216	233
Concho	3	3,732	10
Cooke	286	14,719,914	40,329
Cottle	1	0	0
Crane	451	9,273,683	25,407
Crockett	5,413	45,648,461	125,064
Crosby	1	0	0
Culberson	361	178,596,670	489,306
Dallas	23	4,458,347	12,215
Dawson	14	35,033	96
Denton	2,945	184,362,539	505,103
Dewitt	816	118,255,869	323,989
Dickens	1	0	0
Dimmit	1,719	195,219,071	534,847
Donley	4	9,617	26
Duval	390	9,079,877	24,876
Eastland	181	496,443	1,360
Ector	95	1,497,569	4,103
Edwards	267	4,089,827	11,205
Ellis	49	2,980,134	8,165
Erath	94	2,054,025	5,627
Fayette	222	5,093,888	13,956
Fisher	12	30,031	82
Foard	125	29,249	80
Fort Bend	114	6,550,901	17,948
Franklin	29	908,822	2,490
Freestone	2,960	104,349,387	285,889
Frio	93	1,192,798	3,268
Gaines	18	18,229	50
Galveston	26	1,509,076	4,134
Garza	12	9,877	27
Glasscock	161	1,878,949	5,148
Goliad	344	6,307,403	17,281
Gonzales	16	303,531	832
Gray	851	5,683,704	15,572

County	Count of 2017 Total Gas Disposed	Sum of 2017 Total Gas Disposed (Mcf)	Daily Average 2017 Total Gas Disposed (Mcf/day)
Grayson	62	1,154,657	3,163
Gregg	658	13,399,322	36,710
Grimes	192	5,669,453	15,533
Hamilton	11	22,882	63
Hansford	680	8,679,063	23,778
Hardeman	5	535	1
Hardin	102	4,310,022	11,808
Harris	128	8,717,660	23,884
Harrison	1,210	21,831,685	59,813
Hartley	65	945,356	2,590
Haskell	2	28,006	77
Hemphill	2,409	105,931,440	290,223
Henderson	337	7,140,284	19,562
Hidalgo	1,343	55,199,306	151,231
Hill	222	10,938,750	29,969
Hockley	10	991	3
Hood	657	37,958,057	103,995
Hopkins	7	57,380	157
Houston	57	1,289,481	3,533
Howard	81	2,228,956	6,107
Hutchinson	454	4,077,296	11,171
Irion	193	1,390,874	3,811
Jack	1,073	8,329,638	22,821
Jackson	137	3,054,974	8,370
Jasper	116	9,218,715	25,257
Jefferson	145	8,672,636	23,761
Jim Hogg	199	7,054,948	19,329
Jim Wells	226	3,220,382	8,823
Johnson	2,767	200,326,143	548,839
Jones	9	33,288	91
Karnes	792	118,621,850	324,991
Kenedy	166	14,156,587	38,785
Kent	3	3,388	9
King	3	3,497	10
Kleberg	180	6,462,631	17,706

County	Count of 2017 Total Gas Disposed	Sum of 2017 Total Gas Disposed (Mcf)	Daily Average 2017 Total Gas Disposed (Mcf/day)
Knox	1	0	0
La Salle	959	111,232,822	304,747
Lamb	2	0	0
Lavaca	506	21,877,662	59,939
Lee	72	658,794	1,805
Leon	559	31,482,427	86,253
Liberty	125	8,776,975	24,047
Limestone	1,122	37,126,545	101,717
Lipscomb	1,404	43,775,677	119,933
Live Oak	554	50,068,936	137,175
Loving	371	75,143,833	205,874
Lubbock	3	0	0
Madison	154	2,806,559	7,689
Marion	61	888,963	2,436
Martin	97	1,248,066	3,419
Matagorda	201	7,299,395	19,998
Maverick	82	1,195,762	3,276
Mc Mullen	824	34,810,804	95,372
Medina	2	213	1
Midland	193	8,206,879	22,485
Milam	10	22,523	62
Mitchell	9	33,563	92
Montague	814	59,356,002	162,619
Montgomery	109	2,594,667	7,109
Moorez	1,188	19,523,417	53,489
Nacogdoches	628	15,194,329	41,628
Navarro	29	491,924	1,348
Newton	42	2,701,446	7,401
Nolan	29	194,743	534
Nueces	527	9,333,292	25,571
Ochiltree	716	15,050,635	41,235
OFFSHORE	110	7,386,206	20,236
Oldham	2	26,292	72
Orange	48	4,192,405	11,486
Palo Pinto	443	3,738,553	10,243

County	Count of 2017 Total Gas Disposed	Sum of 2017 Total Gas Disposed (Mcf)	Daily Average 2017 Total Gas Disposed (Mcf/day)
Panola	3,181	71,515,554	195,933
Parker	1,229	63,283,391	173,379
Pecos	1,216	47,624,452	130,478
Polk	164	33,810,709	92,632
Potter	472	5,825,028	15,959
Rains	1	0	0
Reagan	71	2,058,657	5,640
Real	6	119,493	327
Reeves	567	152,858,171	418,790
Refugio	170	1,173,719	3,216
Roberts	860	34,943,740	95,736
Robertson	895	69,320,307	189,919
Runnels	1	0	0
Rusk	1,508	26,234,919	71,876
Sabine	4	147,741	405
San Augustine	52	3,006,054	8,236
San Jacinto	69	2,674,938	7,329
San Patricio	168	5,581,096	15,291
Schleicher	608	4,449,219	12,190
Scurry	11	729	2
Shackelford	72	398,535	1,092
Shelby	291	10,108,208	27,694
Sherman	841	13,277,464	36,377
Smith	417	7,496,147	20,537
Somervell	82	4,569,304	12,519
Starr	1,057	35,660,781	97,701
Stephens	393	1,608,532	4,407
Sterling	623	2,831,482	7,757
Stonewall	4	15,038	41
Sutton	5,530	25,603,789	70,147
Tarrant	3,886	455,347,551	1,247,528
Taylor	3	0	0
Terrell	629	22,036,340	60,374
Terry	1	7,055	19
Throckmorton	22	55,471	152

County	Count of 2017 Total Gas Disposed	Sum of 2017 Total Gas Disposed (Mcf)	Daily Average 2017 Total Gas Disposed (Mcf/day)
Tom Green	3	56,369	154
Trinity	5	21,021	58
Tyler	96	4,770,910	13,071
Upshur	536	13,805,149	37,822
Upton	307	10,145,582	27,796
Uvalde	1	0	0
Val Verde	215	4,642,560	12,719
Van Zandt	10	342,855	939
Victoria	175	3,014,491	8,259
Walker	17	1,094,060	2,997
Waller	49	1,531,906	4,197
Ward	269	15,662,753	42,912
Washington	159	11,119,389	30,464
Webb	6,134	810,399,442	2,220,272
Wharton	397	10,779,086	29,532
Wheeler	1,586	105,703,727	289,599
Wichita	10	20,405	56
Wilbarger	6	2,913	8
Willacy	103	4,628,014	12,679
Wilson	2	1,255	3
Winkler	264	7,369,961	20,192
Wise	4,264	188,701,347	516,990
Wood	32	788,715	2,161
Yoakum	8	2,775	8
Young	226	1,058,229	2,899
Zapata	2,821	78,992,045	216,417
Zavala	60	301,103	825
TOTAL	**90,967**	**4,622,690,291**	**12,664,905**

Permian Basin Core	4,924	359,040,444	983,672
Permian Basin Fringe	1,075	183,521,101	502,798
	5,999	**542,561,545**	**1,486,470**
Eagle Ford	**15,428**	**1,598,388,046**	**4,379,145**
>1,000 others	**47,553**	**1,822,248,036**	**4,992,460**

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