up in FLAMES

U.S. Shale Oil Boom Comes at Expense of Wasted Natural Gas, Increased CO_2

AUGUST 2014

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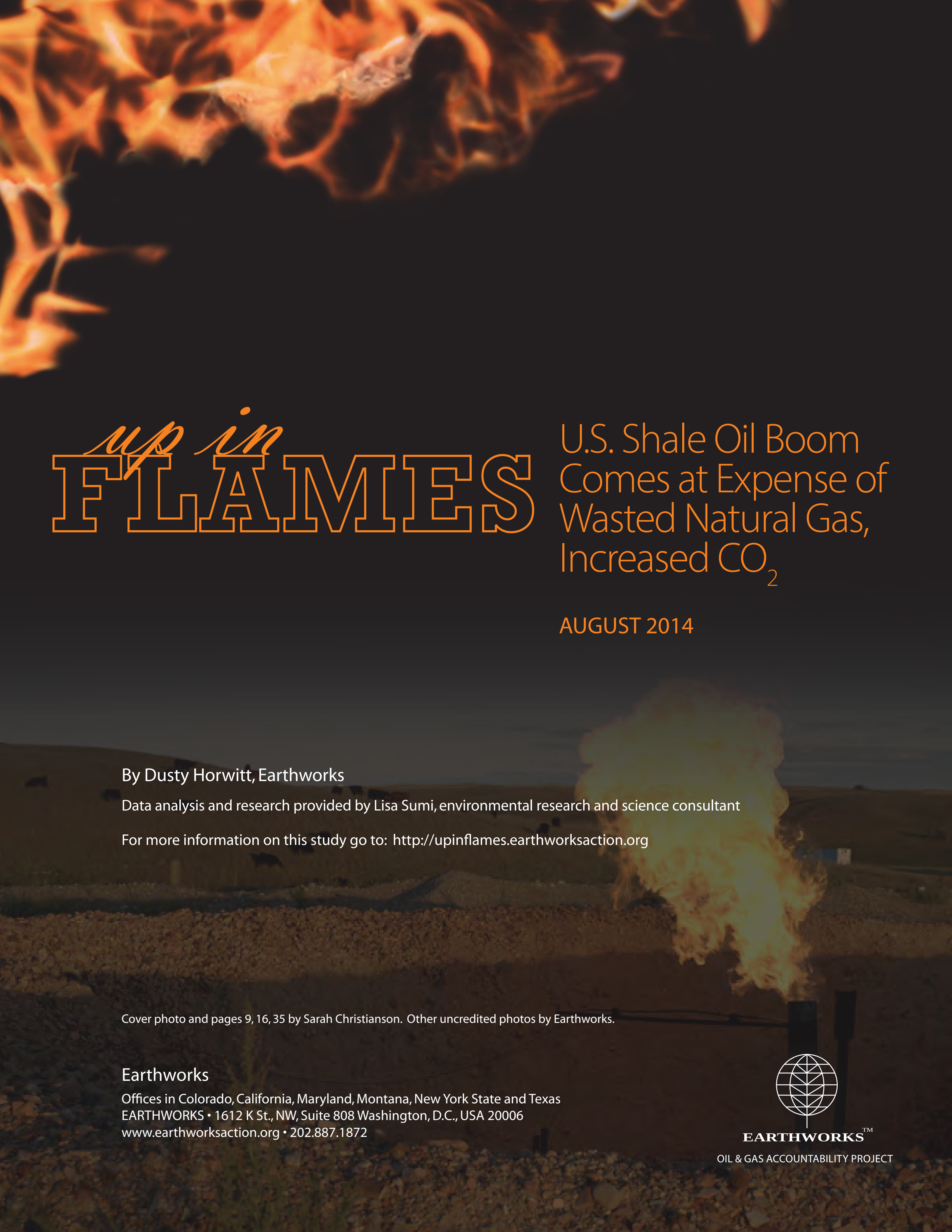

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For more information on this study go to: http://upinflames.earthworksaction.org

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Karnes County, Texas. Photo by Sharon Wilson, Earthworks.

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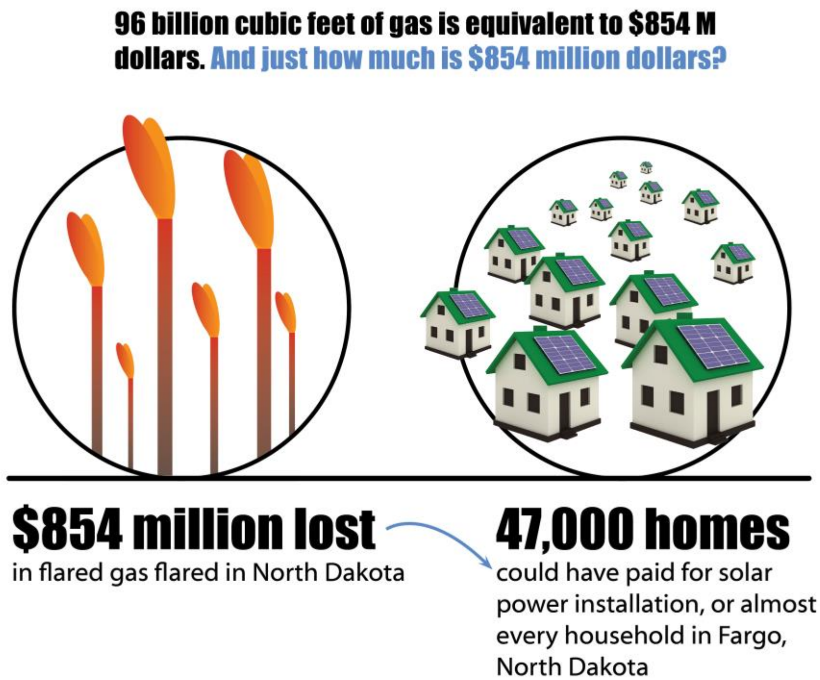
Executive Summary

In a new investigation of flaring of natural gas in the nation's two most prolific shale oil formations, North Dakota's Bakken Shale and Texas' Eagle Ford Shale, Earthworks found that North Dakota oil companies have flared more than $854 million of natural gas since 2010, and state officials do not track how much money companies owe in taxes for the gas. The report found that Texas does not tax flared gas at all, pointing to the need for more stringent measures to reduce flaring in both formations and raising questions about whether North Dakota officials will enforce recently issued regulations to control flaring.



The Bakken and Eagle Ford have gained headlines as the nation's leading formations for shale oil production, but that oil is being produced at a significant cost in associated natural gas that is simply burned off into the atmosphere, needlessly increasing greenhouse gas emissions and creating a potential health hazard for nearby residents.

Earthworks examined records from the North Dakota Industrial Commission's Division of Oil and Gas and the Railroad Commission of Texas (Texas' oil and gas drilling regulator) and found that:

- Wells in the Bakken flared 96 billion cubic feet of gas in 2013, 31% of all gas produced in the formation and almost all of it from oil wells. In comparison, recent estimates of natural gas flared and vented from oil and natural gas wells on public lands have ranged from 0.13 to 5%. Flaring in the Bakken generated about 11.4 billion pounds of carbon dioxide in 2013, the equivalent of a year's worth of carbon emissions from 1.1 million cars and light trucks.

- Oil drillers in North Dakota are allowed to flare natural gas tax- and royalty-free for the first year of production. Wells drilled from 2009 to 2012 flared almost 134 billion cubic feet of gas tax-free in their first year of production, costing the state more than $17 million in lost revenue and an opportunity to discourage flaring because the wells flared a disproportionate amount of gas during their first year.
- State regulators do not track how much tax is paid on flared gas or which wells are paying taxes on flared gas making it difficult to know how much money the state is earning or losing from flaring and whether companies are complying with the law. Such lax regulation is typical of oil and gas drilling oversight across the nation.
- The tax rate on natural gas produced in North Dakota including flared gas is about two percent of the value of the gas, giving drillers little economic incentive to curtail flaring.
- North Dakota generally requires drillers to reduce flaring or else begin paying taxes and royalties on flared gas after the first year. Drillers can continue flaring tax- and royalty-free by taking various steps including requesting a continued exemption from taxes and royalties due to "economic infeasibility" of connecting to a pipeline or otherwise reducing flaring. Between 2009 and 2013, there were more than 4,600 wells flaring natural gas in North Dakota, yet drillers were granted just 112 exemptions out of only 178 requests to continue flaring beyond the first year tax- and royalty-free. It is all but certain that most flaring comes from wells without the exemption for economic infeasibility. Two-thirds of flared gas in the state comes from wells that have an exemption to flare tax- and royalty-free beyond the first year by virtue of being connected to pipelines.

State regulators do not track how much tax is paid on flared gas or which wells are paying taxes on flared gas making it difficult to know how much money the state is earning or losing from flaring and whether companies are complying with the law.

- Oil and gas wells in Texas' Eagle Ford Shale flared 34 billion cubic feet of gas in 2013, 54% of gas flared from all oil and natural gas wells in the state even though wells in the Eagle Ford comprise only 3.2% of all the state's oil and gas wells. Almost 90% of the flaring came from oil wells in the formation. The amount of gas flared from those oil wells was 7.2% of the total gas produced from the wells.
- Eagle Ford Shale oil wells flared about 3.5 billion pounds of carbon dioxide in 2013, equal to a year's worth of carbon emissions from about 350,000 cars and light trucks.
- Texas issued more than 3,000 permits in 2013 that allowed companies flaring more than 50,000 cubic feet of gas per day to flare for longer than 10 days, up from 107 in 2008.
- Under Texas law, drilling companies pay no taxes on flared gas.

Earthworks makes the following recommendations to reduce flaring from shale oil wells:

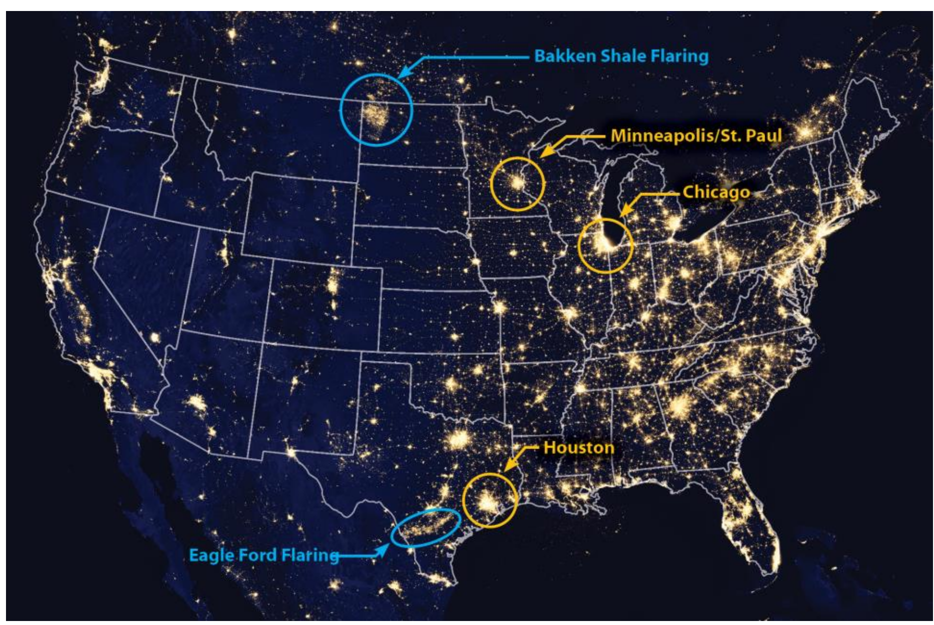
1. **Drillers must have a plan in place to limit flaring before drilling begins** that will result in the capture of all natural gas except that which is technically infeasible to capture. North Dakota has recently taken an important step in this direction, but the state's new plan would allow at least some gas to be flared that is technically possible to collect.

2. **Companies should pay taxpayers full market value for gas that is flared** (with exceptions only for gas that could not technically be recovered such as gas flared in an emergency). North Dakota, Texas and other oil producing states prohibit waste of gas. Yet when gas is flared and no tax is paid, the resource is completely wasted. Paying full value would provide the strongest incentive to conserve the gas, reducing pollution while compensating taxpayers for what has been lost: the total value of the gas.

3. **States should track how much tax drillers pay on flared gas and which drillers are paying.** North Dakota does not do this, which prevents the public from knowing how much money the state earns and loses and whether companies are obeying the law.

4. **States should implement measures to track the amount of gas flared and vented** that go beyond self-reporting by drilling companies and should require measurement of all natural gas flared and vented. Because flaring can be subject to penalties in North Dakota and Texas, companies have an incentive to underreport how much gas they flare. Regulators should find ways to mitigate this conflict of interest through independent or technological monitoring.

5. **Regulators should tighten enforcement on companies that flare illegally.** In Texas, regulators sent warning letters to several companies for failing to obtain a flaring permit at many different well sites. In North Dakota, two operators repeatedly violated the Industrial Commission's flaring rules. All companies that illegally flare should receive penalties, and repeat offenders should be penalized to the extent of the law.



The lights from flared gas are as bright as major cities. Graphic created from NASA satellite image, http://eoimages.gsfc.nasa.gov/.

Introduction

Over the past five years, oil production has increased dramatically from the Bakken Shale, located primarily in central and western North Dakota, and the Eagle Ford Shale located in Texas south of San Antonio. Drillers have accessed oil that was previously uneconomic to produce using the same combination of horizontal drilling and high-volume hydraulic fracturing they have employed to increase natural gas production elsewhere.[1] However, along with this oil production, drillers have produced associated natural gas. While most of the gas is captured and used for productive purposes, a disproportionate amount, especially in the Bakken, is simply burned off, or flared, into the atmosphere because there is insufficient pipeline capacity to accommodate it. Flaring needlessly increases carbon dioxide releases from oil and gas production and wastes resources that could be put to productive use. Incomplete combustion of the flared gases also creates pollutants that may put the health of nearby residents at risk.[2]

Earthworks undertook this report to shed light on the regulatory landscape in both states so that citizens and policymakers can better understand the regulatory levers and how they might be modified to reduce flaring.

While numerous news outlets and others have examined this phenomenon, particularly in the Bakken, there has been less analysis of the regulatory mechanisms behind the exorbitant rates of flaring. Earthworks undertook this report to shed light on the regulatory landscape in both states so that citizens and policymakers can better understand the regulatory levers and how they might be modified to reduce flaring. Our investigation found that standards in both states are weak and that much of the gas is allowed to be flared without payment of any taxes, an apparent violation of both states' prohibitions on "waste" of oil and natural gas resources.

Without payment of taxes, citizens are not only being denied productive use of the resource when it is burned off into the air; they are being denied all of its value. We found that:

- a significant quantity of gas in North Dakota is flared from wells in the first year of oil production tax- and royalty-free;
- a major mechanism in North Dakota's law designed to reduce flaring is little-used;
- North Dakota regulators do not track how much drillers pay in taxes on flared gas or which wells are paying the tax;
- the tax rate on flared gas in North Dakota is extremely low;
- drillers pay no taxes on flared gas in Texas;
- When companies violate flaring standards in both states, enforcement appears to be poor. New rules implemented by North Dakota are a step forward but contain loopholes that might prevent significant reductions in flaring.

Much of the gas is allowed to be flared without payment of any taxes, an apparent violation the state's prohibitions on "waste" of oil and natural gas resources.

Section 1.
Oil Production from Bakken and Eagle Ford Shale Formations on the Rise

Since 2008, oil production has skyrocketed in the Bakken and Eagle Ford Shales. The amount of oil produced from the Bakken has increased from 147,600 barrels per day in January 2008 (about three percent of the U.S. total of 5.1 million barrels per day) to more than a million barrels per day in April 2014 (about 12% of total U.S. production of 8.4 million barrels per day).[3]

The amount of oil produced from the Eagle Ford has increased from about 53,000 barrels per day in January 2008, (about one percent of total U.S. production), to 1.3 million barrels per day in April 2014, (about 16% of the U.S. total).[4] Together, the two formations now produce 2.3 million barrels per day, almost 30% of U.S. oil production.

Comparison of Oil Production from the Bakken and Eagle Ford Shales

Eagle Ford Shale monthly oil production surpassed Bakken production in November 2012. Between 2007 and 2012 the Bakken produced more oil per year than the Eagle Ford Shale. In November 2012, however, daily oil production in the Eagle Ford surpassed production in the Bakken.[5] In June of 2014, the Eagle Ford Shale was producing 1.4 million barrels of oil per day, while the Bakken was producing closer to 1.1 million barrels.

Both the Eagle Ford and Bakken Shale formations produce gas, too. As of March 2014, the North Dakota Industrial Commission, the state's oil and gas regulator, identified four production fields in the Bakken formation: Bakken, Sanish, Three Forks and Bakken/Three Forks.[6] While the Bakken primarily produces oil, the formation contains some wells that produce only natural gas.[7] As of March 2013, the Eagle Ford had 17 producing fields: three produced oil only; seven produced natural gas only; and seven produced both oil and gas.[8]

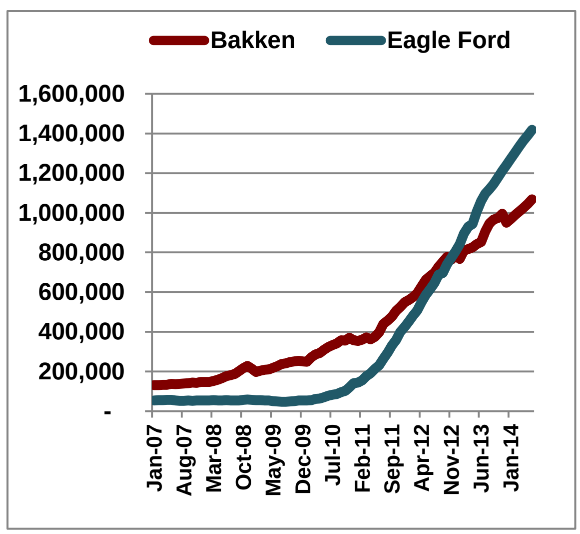


FIGURE 1. Oil production from the Bakken and Eagle Ford Shales (barrels per day)

The Eagle Ford produces considerably more natural gas than the Bakken. In June 2014, the Eagle Ford Shale produced seven billion cubic feet per day, while the Bakken produced 1.3 billion cubic feet per day.[9] Produced gas includes gas that is flared and gas that is captured for use.

In June 2014, the Eagle Ford shale produced seven billion cubic feet per day, while the Bakken produced 1.3 billion cubic feet per day. Produced gas includes gas that is flared and gas that is captured for use. Above, flaring in the Bakken. Photo by Sarah Christianson.

Section 2.
As Oil Production Has Increased, So Has Flaring

Much of the natural gas that is produced along with the oil is not captured and used for beneficial purposes such as heating homes or producing fertilizer; instead, the gas is simply burned off into the atmosphere because there is not enough pipeline capacity or other economic alternatives to accommodate it.[10]

Several observers have reported that the flaring is driven by low natural gas prices and high oil prices that provide significant incentives to drill for oil and little incentive to capture the gas.[11] Geoscientist David Hughes who has studied energy production from the Bakken and Eagle Ford formations has found that only 18 percent of the energy produced from the Bakken field is in the form of natural gas (the rest is oil) while only 37 percent of the energy produced from the Eagle Ford field is natural gas. Given the price differential between gas and oil (gas is only worth a third or less that of oil on an energy equivalent basis),[12] oil accounts for 94 percent of the value of energy produced from the Bakken field and 88 percent of the value of energy produced from the Eagle Ford field.[13] The North Dakota Pipeline Authority reported in October 2013 that liquids in the natural gas make the gas even more valuable ($6.50-$8.00 per thousand cubic feet) than dry gas ($3.34 per thousand cubic feet at the time) and thus economic to capture.[14] However, Hughes said that even if the gas could command higher prices, oil produced from Bakken wells would still be much more valuable. Therefore, without adequate regulations to limit flaring, and enforcement of those regulations, companies will continue to have little incentive to capture more natural gas.

Wells in the Bakken flared 96 billion cubic feet of gas in 2013, 31 percent of all gas produced in the formation and almost all of it from oil wells.[15] In comparison, recent estimates of natural gas flared and vented from oil and natural gas wells on public lands have ranged from 0.13 to five percent.[16] Oil and gas wells in Texas' Eagle Ford Shale flared 34 billion cubic feet of gas in 2013, 54 percent of gas flared from all oil and natural gas wells in the state even though wells in the Eagle Ford comprise only 3.2 percent of all the state's oil and gas wells.[17] About 29 billion cubic feet of the flared gas, or 87 percent, came from oil wells. The amount of gas flared from those oil wells was 7.2 percent of the total gas produced from the wells.[18]

Flaring is harmful and wasteful in several ways. Flaring can produce air pollution with negative impacts locally due to volatile organic compounds such as benzene.[19] Flaring also deprives states of tax revenue and royalty owners of proceeds while ensuring that gas that could have been put to productive use is gone forever.

A significant problem with flaring is that carbon dioxide is emitted when natural gas is flared, thus contributing to climate change. From a climate perspective, flaring is better than venting natural gas (simply releasing it unburned into the air) because methane, a major component of natural gas, is 86 times more powerful as a greenhouse gas than carbon dioxide over a 20-year period and 34 times more powerful over 100 years.[20] However, companies should not waste natural gas through either venting or flaring. If companies produce natural gas while drilling for oil, the gas should be put to use for home heating and other constructive purposes while also contributing to state tax revenues and royalty owners' pocketbooks.

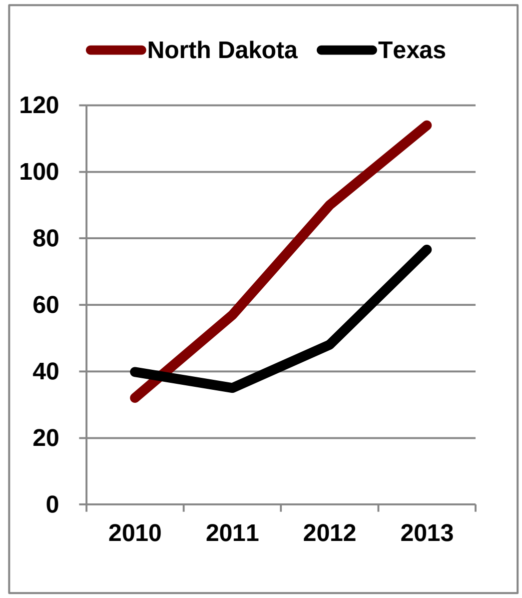


FIGURE 2. Total gas flared in North Dakota and Texas (bcf).

Scope of Oil and Gas Flaring in North Dakota and Texas

Texas flares less gas from all oil and gas operations than North Dakota, but flaring is increasing in both states. Many different facilities involved in oil and gas production flare gas. Both Texas and North Dakota track data on flaring from oil and gas wells, and gas processing facilities and plants.[21]

In 2010, Texas and North Dakota were flaring similar volumes of gas from their oil and gas operations. In 2013, flaring from wells and gas plants in Texas reached 77 billion cubic feet (bcf),[22] while North Dakota flared 114 bcf.[23]

Oil well flaring is now the number one source of flared gas from oil and gas operations in Texas and North Dakota. In 2010, gasoline plants, which extract liquid hydrocarbons from natural gas, were the largest source of flared gas from oil and gas operations in Texas. Starting in 2011, however, associated (casinghead) gas from oil wells became the largest source, and by 2013 it dwarfed all other types of flaring. In North Dakota gas plant flaring has been minor for several years compared to flaring from wells.[24]

In 2010 and 2013, North Dakota gas plants flared four and eight percent of the gas flared by oil and gas wells in those years respectively.[25]

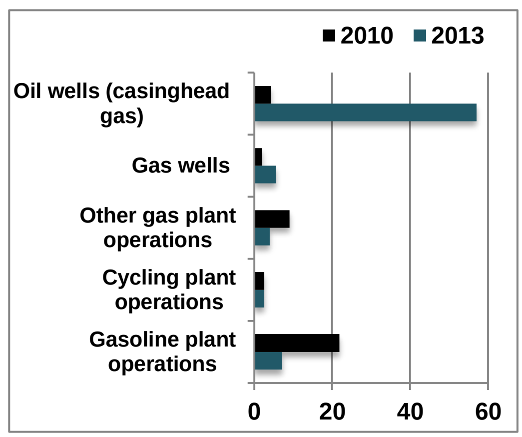


FIGURE 3. Comparison of sources and volumes (bcf) of gas flared in Texas.

Flaring from Bakken and Eagle Ford Shale Oil and Gas Wells

Gas flared from shale oil wells in the Bakken and Eagle Ford comprises a significant percentage of all natural gas flared in North Dakota and Texas. As seen in Figure 2, in 2010, Texas and North Dakota were flaring similar volumes of gas from their oil and gas operations. In 2013, flaring from wells and gas plants in Texas reached 77 billion cubic feet (bcf). Forty-four percent of that flared gas (34 billion bcf) came from Eagle Ford oil and gas wells,[26] even though those wells comprised just 3.2 percent of all oil and gas wells in Texas at the end of 2013.[27] North Dakota flared 114 bcf from wells and gas plants in 2013 -- 96 billion (84 percent) of this was from Bakken wells.[28] Between 2010 and 2014, wells in the Bakken flared 263 billion cubic feet of gas worth more than $854 million.[29]

Flaring from Bakken and Eagle Ford Shale wells has increased significantly

In 2010, oil and natural gas wells in the Bakken flared about 18 billion cubic feet of gas. In 2013, they flared 96 billion cubic feet, almost all of it from oil wells.[30]

In 2010, oil and natural gas wells in the Eagle Ford flared about two billion cubic feet of gas. In 2013, they flared 34 billion cubic feet, about 87 percent from oil wells.[31]

The amount of gas flared is so large, especially in the Bakken, that it compares favorably with the volume of gas produced for use from shale gas formations in other states (See Figure 5). Compare 96 billion cubic feet of gas flared in 2013 from Bakken wells with 108 billion cubic feet of gas produced from shale gas wells in Michigan in 2012 and 345 billion cubic feet of gas produced from shale gas wells in West Virginia in 2012.[32]

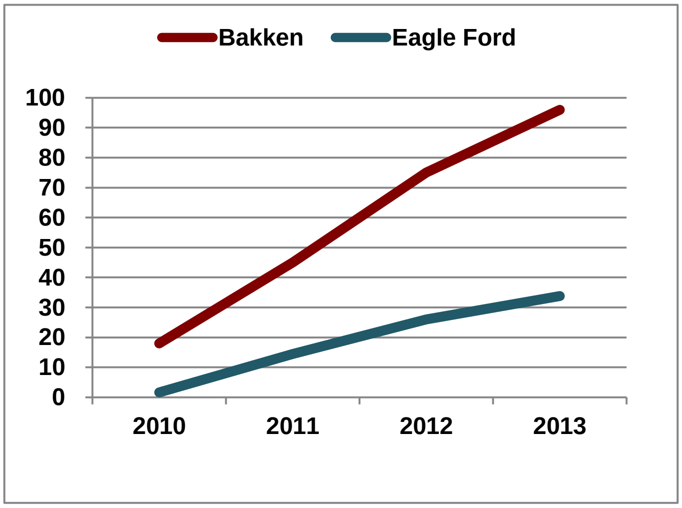


Figure 4. Total annual flaring from Bakken and Eagle Ford Shale wells (billion cubic feet of gas).

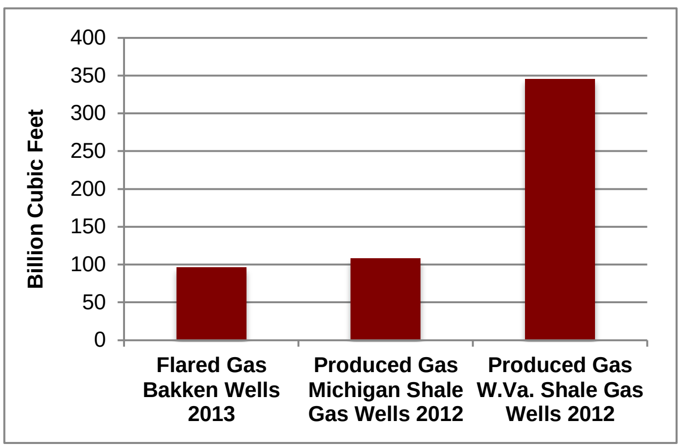


Figure 5. Gas flared from the Bakken compared to shale gas produced in other states.

In Texas, flaring from Eagle Ford wells has predominated in recent years, but flaring from other oil and gas fields is on the rise

Between 2010 and 2013 flaring in the EFS experienced a 1,900% increase (from 1.6 to 34 bcf), although the growth in flaring slowed between 2012 and 2013.

Gas flared from non-EFS oil and gas fields initially increased at a slower pace, but experienced a large jump (24 bcf) between 2012 and 2013, which suggests flaring is becoming a more widespread practice throughout the state.

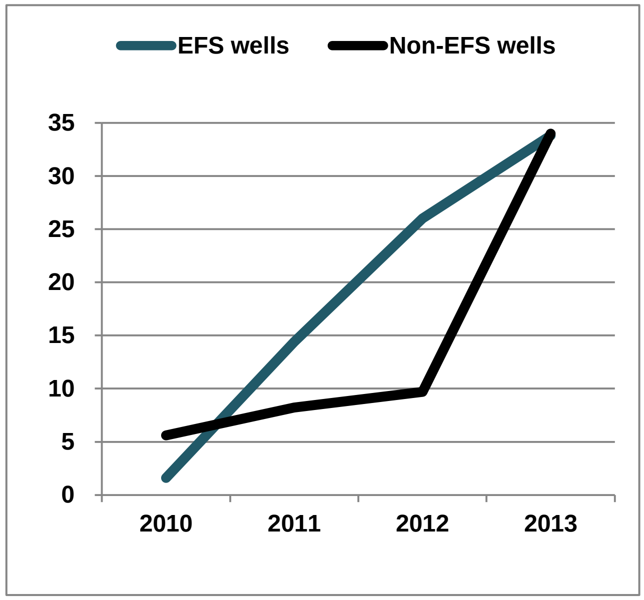


Figure 6. Annual volumes of gas flared from EFS and non-EFS wells (billion cubic feet).

FLARING CLIMATE AND HEALTH IMPLICATIONS

Assuming 100% combustion efficiency,* in 2013, the 96 billion cubic feet of natural gas flared in the Bakken Shale produced the same amount of carbon dioxide emissions as approximately 1.1 million cars and light trucks over a year.[33] The 29.6 billion cubic feet of natural gas reportedly flared** by oil wells in the Eagle Ford Shale in 2013 produced the same amount of carbon dioxide emissions as approximately 350,000 cars and light trucks over the course of a year.[34]

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* Complete combustion of methane and other hydrocarbon gases produces water and carbon dioxide. But most flares are not that efficient. Although it is often reported that flare efficiency is 98% or higher, these numbers assume that equipment is in top condition and the mix of air and gas is ideal to achieve complete combustion. It should be noted, too, that operating conditions such as wind speed can also affect the efficiency of flares. Incomplete combustion of flared natural gas releases chemicals that may endanger health, such as volatile organic compounds like benzene, polycyclic aromatic hydrocarbons, soot, and if present, hydrogen sulfide.[35] Such emissions also contribute to ozone and may make it difficult for areas such as San Antonio, Tex. near the Eagle Ford Shale to meet federal air pollution standards.[36]

** It is highly likely that more natural gas was flared in the Eagle Ford Shale but was not reported by drilling companies. Texas allows reporting exemptions for gas "not readily measured in the operation of oil wells" including "gas released at a wellsite during drilling operations and prior to the completion date of the well."[37] Releases exempt from reporting also include "gas released at a wellsite during initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations."[38] In contrast, North Dakota requires reporting of all natural gas produced.[39]

Gas wells contribute a negligible percentage of the gas flared in the Bakken and a small percentage of gas being flared from the Eagle Ford. Gas wells in the Bakken contributed less than 0.3% of the gas flared from that shale play in 2013. That same year, gas wells in Eagle Ford Shale fields flared 4.4 billion cubic feet of gas, or 13% of the gas flared from the formation.[40]

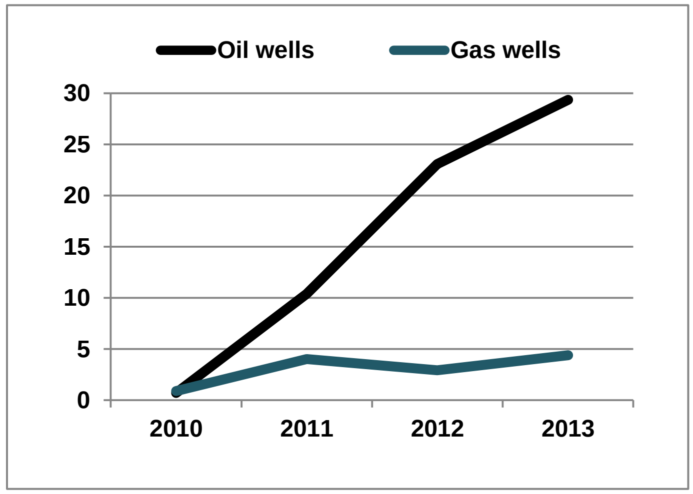


Figure 7. Flaring from oil vs. gas wells in the Eagle Ford Shale (billion cubic feet of gas).

Flaring in DeWitt County, Texas, in the Eagle Ford Shale. Photo by Earthworks.

Section 3.
Top Flaring Companies in the Bakken and Eagle Ford Shales

In 2013 there were 12 companies that flared more than three billion cubic feet of gas from oil wells in the Bakken (top 10 are in the table below).[41] Eight other companies flared between one and three billion cubic feet during that time period. Hess Bakken Investments II, LLC, flared 11.9 billion cubic feet in 2013, more than any other company in the Bakken or Eagle Ford. In terms of flared gas as a percentage of gas produced from their wells, HRC Operating flared the highest at 76%. Other companies, such as Continental and Whiting flared large volumes, but also produced large volumes, so the percentage of gas flared from their wells was much lower (13 and 23%, respectively). Eight of the top 10 companies in the Bakken flared more than 35% of the gas produced from their wells, four flared more than half of the gas that they produced.

In the Eagle Ford Shale, there were only three companies that flared more than three billion cubic feet of gas from their oil wells in 2013,[42] however it is possible that companies might have flared more than they reported due to Texas' exemptions for reporting flared gas in various situations. Four other companies flared between one and three billion cubic feet during that time period. The company that flared the most gas in the Eagle Ford was Chesapeake Operating Company, which flared 6.7 billion cubic feet of gas in 2013. Only one company, EOG Resources, made the top-10 list in both regions.

Generally, the percentage of gas flared from the top 10 companies' oil wells in the Eagle Ford Shale was lower than in the Bakken. As seen from the table below, more than half of the companies flared less than 25% of their gas, although Forest Oil Corporation flared 90% of the gas that it produced from its Eagle Ford Shale oil wells.

Eight of the top 10 companies in the Bakken flared more than 35% of the gas produced from their wells, four flared more than half of the gas that they produced.

Generally, the percentage of gas flared from the top 10 companies' oil wells in the Eagle Ford Shale was lower than in the Bakken. More than half of the companies flared less than 25% of their gas.

Table 1. Top 10 companies flaring gas from the Bakken and Eagle Ford Shale oil wells in 2013.

Top 10 — Bakken	MCF* of gas flared	% of produced gas flared	Top 10 — Eagle Ford	MCF* of gas flared	% of produced gas flared
Hess Bakken Inv. II, LLC	11,886,002	57	Chesapeake Operating Inc.	6,687,608	8
Kodiak Oil & Gas (USA)	8,664,000	46	Murphy E&P Co. USA	5,841,814	37
Statoil Oil & Gas LP	7,226,961	45	EP Energy E&P Co. LP	3,554,539	12
XTO Energy Inc.	6,407,762	50	Comstock Oil & Gas LP	1,989,964	35
HRC Operating LLC	5,525,982	76	EOG Resources Inc.	1,589,028	2
EOG Resources Inc.	5,079,391	39	Carrizo (Eagle Ford) LLC	1,497,148	18
Marathon Oil Co.	4,227,224	36	Goodrich Petroleum Co	1,036,378	15
Continental Resources Inc.	4,164,086	13	Matador Production Co.	740,523	11
Whiting Oil & Gas Corp.	4,107,369	23	Talisman Energy USA Inc.	699,191	26
QEP Energy Co.	3,561,347	65	Forest Oil Corp.	550,963	90

* MCF is 1,000 cubic feet

Some Eagle Ford Shale companies continue to flare increasingly large volumes of gas from year to year (e.g., Chesapeake Operating, Murphy E&P and EP Energy E&P, Comstock).

Eight of the top 10 companies that flared gas in 2013 have had an increasing trend in the volume of gas flared since 2010.[43] The top five companies flaring gas in the Eagle Ford Shale are shown in Figure 8.

Similarly, among the top 10 flaring companies in the Bakken there are several that show an increasing trend in gas flared. We analyzed data for 2013 only.[44]

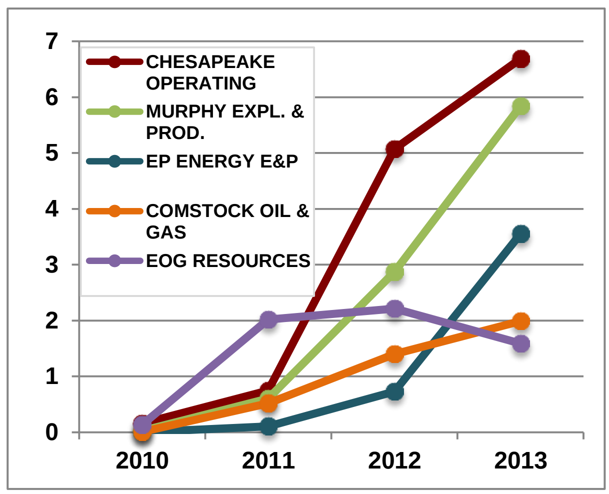


Figure 8. Top five companies flaring gas in the Eagle Ford Shale – 2010 to 2013 (billion cubic feet) of gas flared per year. Note: this chart only shows gas flared from oil wells (not gas wells) operated by these companies in the Eagle Ford Shale.

The companies showing the largest increases from January to December 2013 were:

- QEP – from 40 million cubic feet (Mmcf) in January to 749 Mmcf in December
- Hess – from 1.15 to 1.85 Mmcf[45]
- XTO – from 308 to 787 Mmcf
- Kodiak – from 499 to 974 Mmcf
- EOG – from 240 to 474 Mmcf

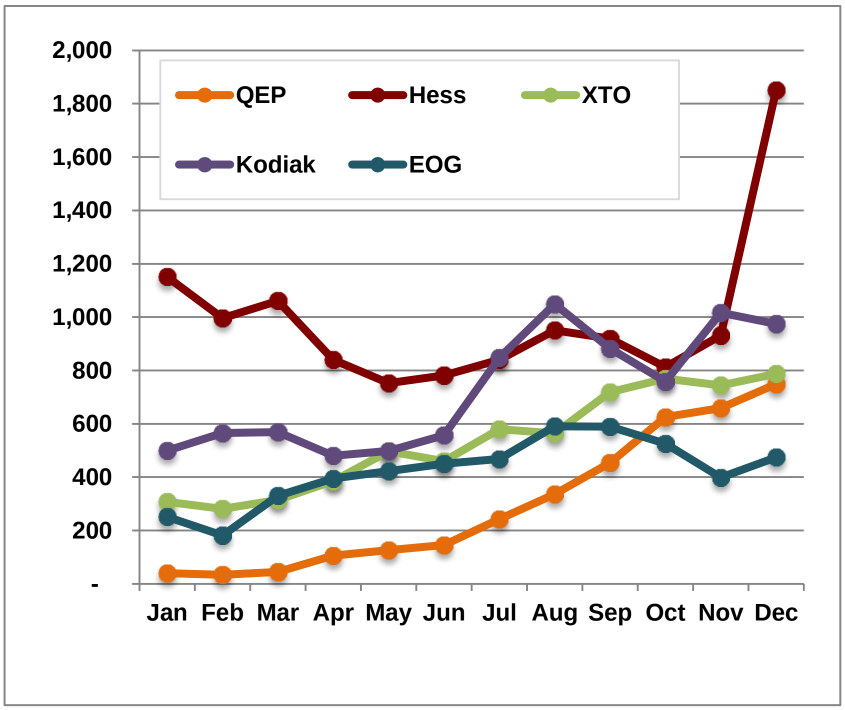


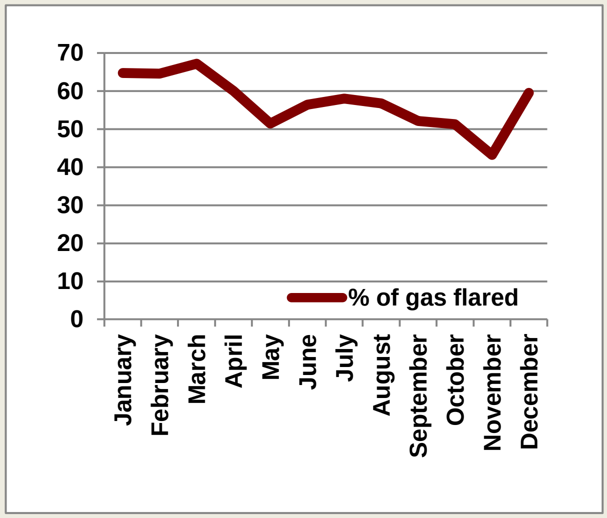
Figure 9. Companies showing increased flaring in the Bakken Shale - 2013 (Million cubic feet (Mmcf) of gas flared per month).

Flaring Reduction Goals vs. Reality

Numerous Bakken operators have publicly stated goals to reduce the percentage of gas that they flare. These companies include Hess, Continental and Whiting, which, as seen in Table 1, are among the top 10 companies in terms of volume of gas being flared from the Bakken. None of these companies have yet met their stated goals.

Hess Corporation: In Hess' 2011 Corporate Sustainability Report the company stated: "We expect to reduce our flaring rate beginning in 2013 to a point below the state's goal of 10 percent flaring for the Bakken region by 2014."[46]

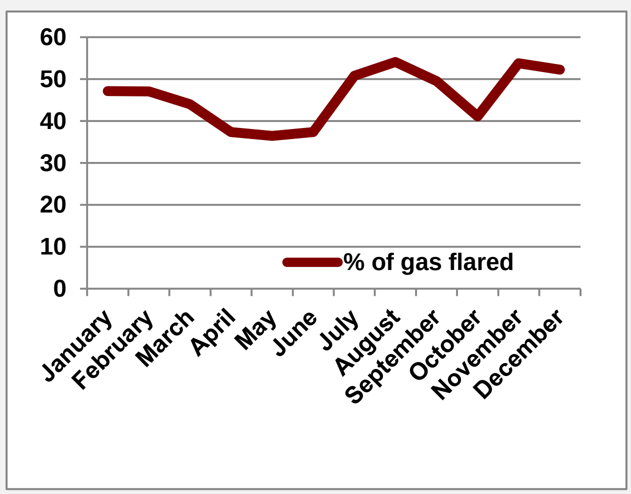
As seen at right, Hess started 2013 flaring approximately 65 percent of the gas it produced in the Bakken. During the year it reduced flaring to 43 percent (in November), but ended the year flaring 60 percent of its produced gas.[47] This latest increase is likely due to upgrades at its Tioga gas processing plant.



HESS: Gas flared from Bakken wells as a % of total gas produced (2013).

Kodiak Oil and Gas: Second only to Hess in the volume of gas flared from the Bakken in 2013, Kodiak managed to reduce its flared gas to under 40 percent for a few months, but ended the year flaring more than 50 percent of the gas it produced in December.[48]

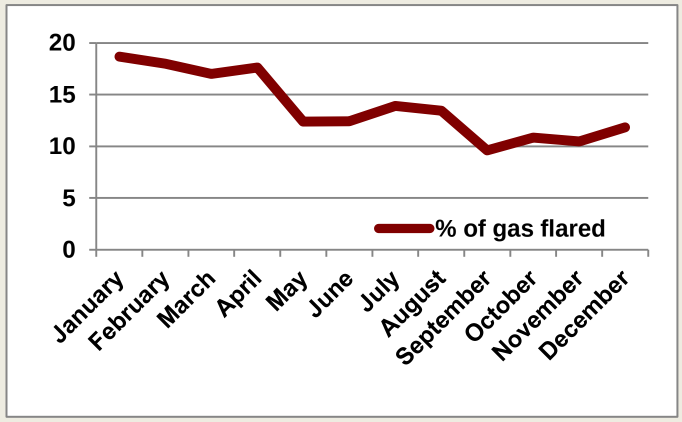
In May 2014, Kodiak publicly stated that it "is working with state and industry representatives to raise captured gas amounts to 75 percent by the end of this year."[49] It remains to be seen if the company will be able to achieve that goal.



KODIAK: Gas flared from Bakken wells as a % of total gas produced (2013).

Continental Resources: In Continental's Annual Report for 2012, the company stated: "Our ultimate goal is to reduce natural gas flaring from our operated well sites to as close to zero percent flaring as possible."[50]

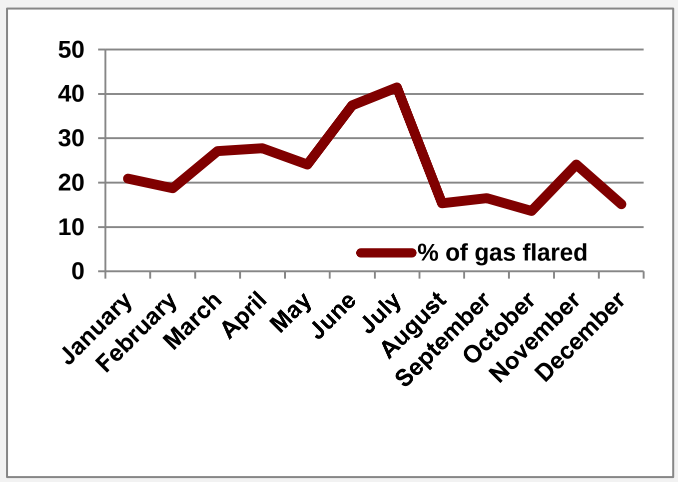
Continental decreased the amount of gas that it was flaring from approximately 19 percent of gas produced to closer to 12 percent by the end of the year.



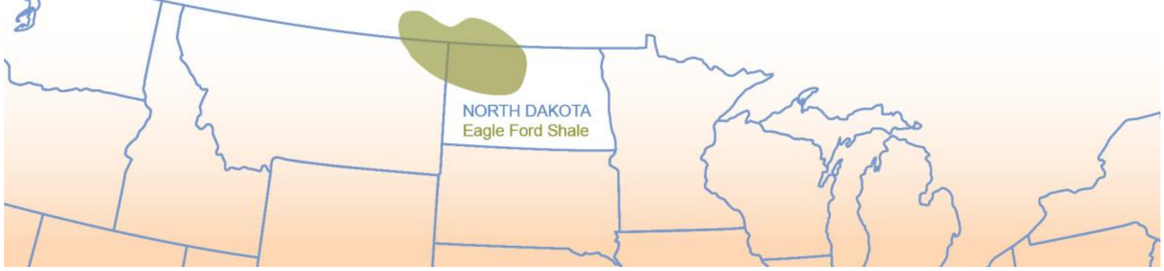
CONTINENTAL: Gas flared from Bakken wells as a % of total gas produced (2013).

Whiting Petroleum: In 2011, Whiting's president stated: "Our goal is to have zero [flaring] emissions."[51]

In 2013, Whiting flared an average of 23 percent of the gas it produced in the Bakken, but on a month-to-month basis the percentage of gas flared varied from a low of 14 percent (October) to a high of 42 percent (July). It ended the year flaring a lower percentage of produced-gas than what it flared at the beginning of the year, but the company has not yet reduced flaring below 10 percent, let alone achieved zero percent flaring.[52]



WHITING: Gas flared from Bakken wells as a % of total gas produced (2013).



Section 4.
Lax Rules for Flaring in North Dakota

North Dakota law and regulations prohibit the "waste" of oil and natural gas,[53] but at least until recently, the law and regulations have simultaneously provided little incentive for companies to reduce flaring from oil wells. This lax regulatory environment is consistent with Earthworks' prior research which found that in 2010, regulators did not inspect more than 50 percent of wells in six different oil and gas drilling states[54] and EnergyWire's reporting that in several drilling states, fines or other enforcement action for violations of oil and gas rules were rare.[55]

North Dakota's statutes provide that gas produced with oil can be flared for up to a year without payment of royalties to private owners of the mineral rights or taxes to the state.[56]

After a year of production, the oil well must be:

- capped, so that the gas does not escape[57]
- connected to a gas gathering line, so that the gas can be sold[58]
- equipped with an electrical generator that uses at least 75% of the produced gas[59]
- equipped with a system that collects at least 75% of the gas and natural gas liquids for beneficial consumption such as by transporting the gas to a processing facility[60]
- equipped with other North Dakota Industrial Commission-approved processes that reduce volume of flaring by more than 60%[61]

In their first year of production, these wells flared more than the total gas PRODUCED by gas shale wells in Michigan.

If wells continue to flare in violation of these standards, operators must pay royalties to private parties and taxes to the state[62] unless the company applies for and receives an exemption to continue flaring due to economic infeasibility of connecting to a pipeline or taking other steps.[63]

Earthworks found that North Dakota's exemption from taxes and royalties for associated natural gas flared during the first year of oil production enables oil producers to flare a significant amount of gas tax- and royalty-free. We examined flaring volumes from Bakken wells that started producing gas in 2009, 2010, 2011 and 2012 that have at least two full years of reported production and found that these wells cumulatively flared close to 134 billion cubic feet of gas in their first year of production (see Table 2). That is more than the total gas that was **produced** in the state in 2010 (see Table 3), more than the total gas produced by Michigan shale gas wells in 2012 and more than a third of the gas produced by West Virginia shale gas wells in 2012.[64]

Table 2. Gas flared from Bakken wells early in their production.[65]

	Number of wells that started producing oil and gas	Number of wells that have never flared	Number of wells that flared in the past year (June 2013 – May 2014)	Cumulative volume of gas flared by wells in first year of production (MCF)	Average gas flared per well in first year of production (MCF)*	Cumulative volume of gas flared in first three months of production (MCF)	Average gas flared per well in first 3 months of production (MCF)*
2009	470	20	403	6,908,575	15,352	3,354,401	7,454
2010	766	46	662	20,099,522	27,916	8,692,255	12,073
2011	1,227	69	1047	42,846,315	37,000	19,570,084	16,900
2012	1,814	93	1599	63,928,501	37,146	30,320,319	17,618
Total	4,227	228	3,711	133,782,913	29,354	61,937,059	13,511

* average of wells that flared gas (i.e., does not include those wells that never flared)

Between 2009 and 2012 North Dakota's gas tax rate varied from as little as $0.0914 to as much as $0.1831 per MCF (thousand cubic feet). The average during this time period was $0.1295.[66] Based on this average, North Dakota lost more than $17 million dollars in tax revenue due to the tax exemption provided to gas flared during the first year of a well's production.[67] The state likely lost even more tax revenue due to other tax- and royalty exemptions such as those that allow companies to continue to flare 25 or even 40 percent of their gas tax- and royalty-free as long as they use the rest for beneficial purposes.[68]

It is difficult to know exactly how much tax revenue the state earned or lost on flared gas because neither the state Tax Department nor the state Department of Mineral Resources track how much tax is collected on flared gas and the Tax Department lumps together taxes collected on oil and gas.[69] A spokesperson for the Department of Mineral Resources wrote that the department does not track which operators are paying taxes on flared gas or which exemptions they are using to avoid paying taxes on flared gas. Unless the operator applies for an exemption to continue flaring tax- and royalty-free after a year of production, the spokesperson Alison Ritter wrote, "it is presumed they have connected or are in some way utilizing the gas" in compliance with the tax- and royalty-free exemptions, though a field inspector could find a violation. According to a recent report by the North Dakota Pipeline Authority, almost two-thirds of the gas flared in North Dakota comes from wells connected to pipelines,[70] all of which is being flared tax- and royalty-free according to the statute. Operators that are not connected to a pipeline could be flaring tax- and royalty-free within the bounds of the law or they could choose to pay taxes and royalties if they exceeded the law's standards, or they could be flaring without paying taxes and royalties in violation of the law, but the state does not track such data.

Our analysis shows that by allowing operators to flare for the first year tax- and royalty-free, North Dakota is missing a significant opportunity to reduce flaring because the volume of gas flared falls sharply with each year that goes by. In subsequent years, drillers would pay much smaller amounts for their flared gas, creating less incentive to reduce flaring. The following chart shows the volume of gas that was flared on an annual basis from wells that started producing gas in 2009.[71]

If flared gas were taxed from first production, drillers would have a much stronger incentive to reduce flaring because a more significant amount of their gas would be subject to tax.

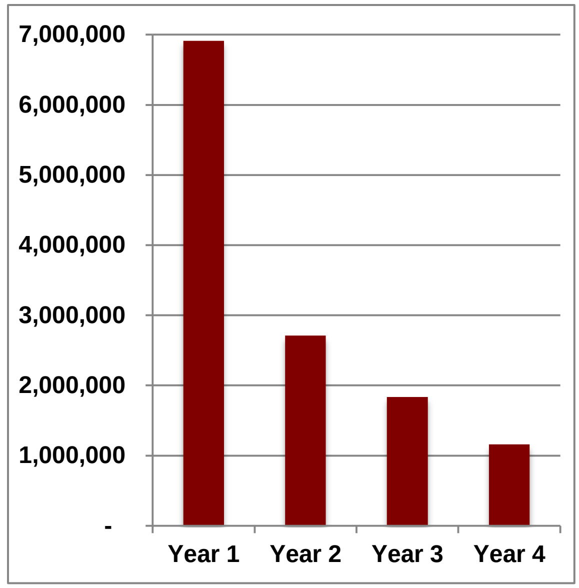


Figure 14. Volume of gas flared (MCF) from wells that started to produce oil and gas in 2009.

Recent Rules Set Goals to Reduce Flaring in North Dakota

According to new rules issued in May 2014 that took effect on June 1, operators must include a “gas capture plan” designed to reduce flaring when they apply for new drilling permits in the Bakken Shale. The plan must include the proposed route through which a new well will connect to an existing gas pipeline, the maximum daily capacity of the existing pipeline and other alternatives to flaring. “Permit consideration may be delayed or stipulations may be imposed (such as production restrictions) if applicant is unable to timely connect the subject well and alternatives to reduce the amount of flared gas will not be implemented,” the state’s oil and gas division wrote.[72]

On July 1, 2014 the state issued additional rules for existing and future oil wells in the Bakken field.[73] In issuing the rules, the state set goals for reducing flaring to 26 percent of gas produced by October 1, 2014, 23 percent by January 1, 2015, 15 percent by January 1, 2016 and 10 percent by October 1, 2020 with a potential to reduce flaring to five percent.[74] Drillers can meet these standards by well, field, county, or statewide.

In general, the rules provide that beginning October 1, 2014, drillers can produce oil and gas from “infill horizontal wells” at a maximum efficient rate for the first 90 days. After that, drillers will be allowed to continue production at the maximum rate if they meet or exceed the targets for flaring reductions (see Table 2).

The state provided an additional exemption for the amount of flared gas emitted during the first 14 days of flowback, the period after a well is hydraulically fractured when injected fluid and gas flow back out of the well.[75] The state does not report what percentage of gas is likely to be emitted during this period. The EPA has found that Reduced Emissions Completion technologies can theoretically capture up to 90 percent of the gas released during flowback if wells are connected to pipelines, suggesting that at least some of this gas could be recovered.[76]

The state excluded from the rule wells that are already exempted from paying taxes and royalties because it is economically infeasible for them to connect to a pipeline or take other measures to reduce flaring. The state also exempted the first horizontal well drilled in a “non-overlapping spacing unit.”[77] Together, these exemptions may slow progress toward the state’s flaring targets.

If drillers fail to meet or exceed the targets at the maximum efficient rate, they will be limited to 200 barrels of oil per day if their monthly flaring rate is 40 percent or less of the total natural gas produced from the well. Drillers will be limited to 100 barrels per day if their flaring rate exceeds the targets and the rate is more than 40 percent of the total natural gas produced from the well.[78] The state does not say how many wells would face such limits and what percentage of the state's flared gas these wells produce. Lynn Helms, the director of the state's Department of Mineral Resources recently told EnergyWire that based on April oil production figures, he expected a four to five percent reduction in oil production due to the new rules. [79]

It is fair to ask whether regulators have the interest or capacity to enforce these relatively complex new rules when under the preexisting rules, the state has failed to monitor how much tax revenue is being collected from flared gas or which wells are paying taxes for flared gas.

Even if Percentage of Gas Flared Decreases, Flaring Volumes Will Likely Remain High

Even if the new regulations are enforced, they could have limited effect due to a projected increase in gas production. The new regulations and the oil and gas industry have stated goals of eventually reducing flaring in the state to 10 percent of gas production or lower.[80] In recent months, there have been celebratory announcements regarding a projected decrease in Bakken flaring due to upgrades at the Hess Tioga gas processing plant. According to Hess, the expansion was expected to reduce the state's overall flaring percentage from 33 percent in March 2014 to the low 20s in April or May 2014.[81] The NDIC reported in July 2014 that the percentage of gas flared in the state had "dropped to 28% as the new Tioga gas plant increased to full capacity."

Ceres, a nonprofit organization that has studied flaring in the Bakken, points out that even if a reduction in flaring to 10 percent of produced gas were achieved by 2020, the total volume of gas being flared would still exceed the amount flared in 2010.[82]

A consultants' report prepared for the North Dakota Pipeline Authority confirms this likelihood. The report found that once the currently planned new gas plant infrastructure is in place by the end of 2014, gas production will quickly outpace capacity again – meaning more new infrastructure is required or more flaring.[83]

As seen in Table 3, total gas production in North Dakota has increased every year for the past few years. The largest recent increase was in 2012, when gas production jumped 66% from 155 million MCF to 259 million MCF. Growth in gas production was smaller in 2013, but still constituted a 34% increase from 2012.

Table 3. Actual volumes and % of gas flared in North Dakota (2010 to 2013).[84]

	Total gas produced in the state (thousand cubic feet, or MCF)	% increase in gas production from previous year	Total gas flared (MCF)	% of produced gas flared
2010	114,387,654	--	30,963,617	27
2011	154,598,806	35	53,783,042	35
2012	258,493,772	67	83,527,247	32
2013	346,951,093	34	106,142,142	31

According to the *New York Times*, "energy experts expect a 40 percent increase in the gas produced from the Bakken field by the end of 2015."[85]

We examined a variety of gas production scenarios, ranging from 0 percent growth in gas production to 40 percent growth, in order to understand the volumes of gas that would be flared if North Dakota was able to reduce flaring to 20 percent of its gas production, and also 15% of production (the January 2016 goal set by North Dakota under its new rules).

Table 4. Scenarios for volume of gas flared in 2014 and beyond (MCF is 1,000 cubic feet).

Gas production growth scenario (% growth in production as compared to 2013)	% increase in gas produced compared to 2013	Estimated gas flared (MCF) assuming 20% of gas is flared statewide	Estimated gas flared (MCF) assuming 15% of gas is flared statewide
0% growth: 346,951,093 MCF produced	0	69,347,808	52,042,664
20% increase in gas production: 416,300, 000 MCF produced	20	83,220,000	62,445,000
30% increase in gas production: 451,100, 000 MCF produced	30	90,200,000	67,665,000
40% increase in gas production: 485,700, 000 MCF produced	40	97,140,000	72,855,000

Table 4 shows that in the unlikely scenario that gas production in North Dakota has stabilized (i.e., there is no growth in gas production in 2014 or beyond), and assuming North Dakota operators achieve a 20% flaring rate, there will still be almost 70 billion cubic feet of gas flared. That is more gas than the total volume flared in 2011.

If there is a 20 percent increase in gas production in 2014 (or any year thereafter) as compared to 2013, and a flaring rate of 20 percent is achieved, the gas flared will be about the same volume that was flared in 2012. A 30 percent or 40 percent growth in gas production will result in flaring volumes that greatly exceed the volume flared in 2012. A 15% flaring rate will result in flaring volumes that exceed the total volume of gas flared in 2011.

Rules Allow Exemptions to Continue Flaring Royalty- and Tax-Free

The new rules do not change the existing North Dakota law that allows producers to obtain an exemption to continue flaring tax- and royalty-free beyond the first year if they can show that connecting the well to a gathering line is economically infeasible currently or in the near future or that a market for the gas is not available and that using the gas to generate electricity or installing a collection system for the gas is economically infeasible.[86] To show that connecting the well to a pipeline is economically infeasible, a producer must prove that over the life of the well, the direct costs of connecting the well to the line and operating the facilities connecting the well to the line would be greater than the amount of money the operator would be likely to receive for the gas, minus production taxes and royalties if the well were connected. Applicants for such an exemption based on economic infeasibility must provide a variety of data including the basis for the gas price used to calculate whether it is economically infeasible to connect the well to a pipeline and the cost of connecting the well to a gas line.[87]

Exemptions Play Little Role in Flaring but Shed Light on Economics

We examined available information on all of the cases in which operators asked the Industrial Commission to let them continue flaring past one year without having to pay taxes and royalties because connecting to a pipeline or taking other steps to reduce flaring was economically infeasible.[88] We found 112 cases between 2009 and 2013 in which operators were granted this exception out of 178 cases considered.[89]

The small number of cases relative to the large number of wells flaring natural gas suggest that the exemptions play a relatively small role in North Dakota's high flaring rate. The North Dakota Pipeline Authority found that during the month of August 2013, there were 4,659 "non-confidential"[90] wells flaring natural gas in North Dakota.[91] Of these, about 2,400 wells accounted for about 97 percent of the natural gas that was flared in the state that month. The authority reported that the more than 600 wells with the highest rate of flaring (1 million to 2.6 million cubic feet per day) accounted for just 10 percent of the state's natural gas flared during the month. So even if all of the 112 cases in which wells received tax and royalty exemptions due to economic infeasibility represented wells within the category of those that flared the most natural gas in August 2013, it is likely that such wells would have flared only a small percentage of the state's total flared natural gas. In other words, the data strongly indicate that most of North Dakota's flared gas is coming from wells that did not receive an exemption to flare tax- and royalty-free beyond a year due to economic infeasibility.

However, it is instructive to examine the year-plus exemptions to better understand the economics and regulation of flaring in North Dakota.

Table 5. NDIC Commission Hearings Related to Flaring Exemptions (2009 to 2013).

	Cases heard	Exemptions granted	Exemptions denied or violations found	Cases dismissed or continued
2009	54	45	0	9
2010	23	20	0	3
2011	15	7	0	8
2012	78	32	18	28
2013	8	8	0	0

As seen in Table 5, the number of flaring exemptions varies from year to year. In our review, we found the highest number of exemptions in 2009, and the second highest number in 2012. The most flaring-related cases were heard in 2012. In that year there were nine instances of exemptions being denied by the Commission; nine cases where the Commission found operators in violation (i.e., they were flaring without an exemption); and 28 cases that were dismissed due to lack of information on the part of the company (or in some cases the company no longer needed the exemption because it was able to hook into a gathering line).

Why did the Commission deny some of the requests?

In the nine cases where exemptions were denied the Commission either heard from the company that the company could make a profit from selling the natural gas rather than flaring it or the agency's own research showed that the companies could make a profit from selling the natural gas rather than flaring it. The box below provides an example of the Commission's denial of a flaring exemption request.

NORTH DAKOTA INDUSTRIAL COMMISSION (NDIC) DENIES BAYTEX EXEMPTION

In April 2012, Baytex appeared before the North Dakota Industrial Commission and provided evidence that:

- the cost of purchasing and installing a 2-mile gas pipeline from their Hall #3-161-98H well to a gathering system would be approximately $225,500
- approximately 170,000 MCF of surplus gas would be available for sale, and the value of the gas was $4.93 per MCF, therefore, the gross value of the gas was estimated to be $838,000.
- based upon a royalty rate of 20% and a gas production tax of $0.115/MCF, Baytex estimated that the royalty and tax burden for the gas produced from the well would be approximately $167,000 and $96,400, respectively. So the net value of the surplus gas would be $574,600. NDIC found that Baytex erred in its calculations, and put the net value of surplus gas at $650,000.[92]

NDIC Order 18243 ruled that "under current market conditions the surplus casinghead gas presently being produced by the well and the estimated recoverable reserves of surplus gas from the well is sufficient to recoup the costs of installing and operating a gas gathering facility connected to the nearest gas gathering system."[93]

Under what circumstances does the Commission grant exceptions?

NDIC's Case Hearing Reports contain varying amounts of information. In some instances, the reports simply said that the company had evidence that it would suffer a net loss in revenue if it were required to stop flaring, but did not provide any details on how those assumptions were supported (e.g., price of gas assumed; total volume of surplus gas that could be sold; cost of connecting to the gathering system). In other cases, there was quite a bit of information to show how the Commission made its decision.

- In their calculations operators tend to use a set sale price for their surplus gas. This does not take into account what happens if the price of gas increases. There was no evidence that the Commission required companies to provide calculations on the price of gas required to make the project viable.
- There was very little information in the files to justify that it would be too expensive to equip well sites with an electrical generator or a system to collect and use the gas and natural gas liquids.

The most detailed and compelling arguments were that the cost of building the infrastructure to capture and sell gas greatly exceeded the value of the gas. In some cases, the loss to the company would have been in the tens of millions of dollars (See Marathon example in box below).

As seen in the Marathon example, we found that even when it was expensive to construct the infrastructure to move the gas, companies were granted exemptions from having to pay taxes and royalties – despite the fact that revenue from the well was more than enough to cover those costs.

EXAMPLE: MARATHON GRANTED AN EXEMPTION

In July 2009, Marathon appeared before for the North Dakota Industrial Commission and provided evidence that:

- the Jack Pennington #21-28H well currently flared 32 MCF per day
- if the well were to be connected to the nearest gas gathering station (13 miles away), the value of the gas reserves would not be enough to recoup the cost of installing and operating the gas gathering facility. The company would lose approximately $23 million.[94]

NDIC Order 13319 ruled that "Considering the amount of surplus gas being produced by the well, the amount of estimated recoverable reserves from the well, and the cost to connect the well to a gas pipeline, it is not economic at this time to connect the well to a gas gathering facility."[95]

Although it is clear from this case that it would be expensive to build the pipeline, it's not clear why the company should be allowed to flare without paying royalties.

The order states that:

If Marathon's request is not granted, taxes and royalties must be paid on flared gas which will increase operating costs, raise the economic limit and cause premature abandonment of the well; or the well must be connected to a gas pipeline at an economic loss which would also cause premature abandonment, or flaring must cease and the well must be "capped," resulting in the loss of oil production and the loss of the benefits of that production by all owners of interest in the well and the State of North Dakota.

It's unclear how the payment of taxes and royalties would cause premature abandonment of this well.

- In July 2009, the month the order was issued, the well was producing 69 barrels (bbl) of oil per day, and oil was selling for approximately $56 per bbl, so oil revenues were around $3,870 per day.[96] The volume of gas being flared was 31,000 cubic feet per day. At a taxation rate of $0.18/MCF the well would have paid $5.70 in taxes, and at a gas price of $3.74 per thousand cubic feet and an estimated royalty rate of 20% it would have paid about $23 in royalties.[97] Clearly there would be some per-day operating costs, but with oil revenues of $3,870 per day would paying daily gas taxes and royalties of $28 truly cause premature abandonment of this well?

There were other cases, however, where the loss to the company was in the range of $10,000 to $100,000.[98] Such costs are likely to be modest especially considering that one of the major drillers in the Bakken, Continental Resources, reported that its average cost of drilling a well in North Dakota in 2013 was $8 million[99] and companies operating in the Bakken have reported profits in the hundreds of millions and billions of dollars.

Table 6. Estimated taxes paid, based on volumes flared per day (MCF is 1,000 cubic feet)

Top 10 Companies Flaring from the Bakken Shale in 2013	2013 Profits Top Ten Companies Flaring in Bakken Shale
Hess Corporation (subsidiary Hess Bakken Inv. II, LLC operates in the Bakken)	$5.05 billion[100]
Kodiak Oil & Gas (USA) Inc.	$141.416 million[101]
Statoil Oil & Gas LP	$6.4 billion[102]
ExxonMobil (subsidiary XTO ENERGY INC. operates in the Bakken)	$32.580 billion total /$4.191 billion U.S. upstream[103]
HRC Operating, LLC	$1.223 billion (loss)[104]
EOG Resources, Inc.	$2.2 billion[105]
Marathon Oil Company	$1.753 billion total, $529 million North American Exploration & Production[106]
Continental Res., Inc.	$764.219 million [107]
Whiting Oil And Gas Corp.	$366 million[108]
QEP Energy Co.	$159.4 million[109]

Why does it matter to companies that they get the exemption? Why not just pay the taxes and royalties?

Taxes: Of those companies receiving exemptions, the volume of surplus gas being flared per day ranged from: 0 to 300,000 cubic feet per day, or between 0 and 109.5 million cubic feet per year. Table 7 shows what an operator would have paid in taxes (per year) in 2009, 2011 and 2013.[110] The most a company would have paid is $20,000 in one year. Most companies that received exemptions would have paid from less than $100 to $7,000.

Table 7. Estimated taxes paid, based on volumes flared per day (MCF is 1,000 cubic feet).

		Total taxes paid per year		
Volume of gas flared per day (MCF)	**Number of wells with exemptions**	**2009 (tax rate $0.1831 per MCF)**	**2011 (tax rate $0.1112 per MCF)**	**2013 (tax rate $0.0833 per MCF)**
0 – 10	14	$0 – 668	$0 – 406	$0 – 304
11 – 50	41	$735 – 3,342	$446 – 2,029	$334 – 1,520
51 – 100	31	$3,408 – 6,683	$2,070 – 4,059	$1,551 – 3,040
101 – 172	13	$6,750 – 11,495	$4,099 – 6,981	$3,071 – 5,230
300	1	$20,049	$12,176	$9,121

North Dakota's gas tax rate from July 2013 to June 2014 was $0.0833 per thousand cubic feet of natural gas,[111] which amounts to a rate of about two percent of the value of natural gas produced in North Dakota in April 2014: $4.23 per thousand cubic feet.[112] In comparison, the tax rate (called a "royalty") for natural gas produced on federal land is 12.5 percent of the value or amount of the gas produced.[113] The state's low tax rate on natural gas combined with the exemption from taxes and royalties on flared gas during the first year of production helps create a significant incentive for companies to continue flaring.

Royalties: Royalties likely amount to a much larger cost to operators than taxes. We found one NDIC hearing case that mentioned a royalty rate, which was 20%. We used this rate as a rough guide (with full realization that royalties paid by companies vary). In 2013, at an average gas price of $3.23 per thousand cubic feet,[114] royalties on 10,000 cubic feet of gas per day would have been $6.46 per day/$2,358 per year. For wells flaring 100,000 cubic feet per day the royalty payments would have been approximately $64.60 per day/$23,579 per year. At volumes of 300,000 cubic feet per day, the royalties would have amounted to more than $70,000 per year.

Flaring-Related Enforcement Actions: North Dakota

By searching the North Dakota Industrial Commission Orders we found nine instances between 2009 and 2014 where companies were found in violation of the North Dakota Century Code (NDCC) Section 38-08-06.4. Baytex Energy was found in violation twice, and Hess Corp. had seven violations of 38-08-06.4.[115]

Section 38-08-16 of the NDCC provides the Commission with the power to impose a civil penalty of up to $12,500 for each offense (and each day the violation continues is considered a separate offence) "unless the penalty for the violation is otherwise specifically provided for and made exclusive."[116] It is clear that at least Hess was aware that it needed to obtain an exemption from the Commission in order to continue flaring gas beyond the first year of production, since it had obtained such exemptions in the years prior to violating the rule.[117] But no penalties were issued to Hess or Baytex for their violations because section 38-08-06.4 provides that violations result in payment of taxes and royalties owed and this is the type of specific and exclusive penalty referred to in section 38-08-16. In all of the Orders the Commission simply required the companies to pay taxes and royalties on the gas flared which they should have been doing by law, anyway.

Section 5.
Lax Rules for Flaring in Texas

Like North Dakota, Texas also prohibits waste of oil and gas[118] yet generally allows flaring under certain conditions.

Operators are allowed to flare for 10 days after a well has been completed.[119] If operators want to flare longer and are flaring more than 50,000 cubic feet per day, they must apply for a flaring permit. These permits are typically issued for 45 days at a time, up to a maximum of 180 days.[120] Operators flaring less than or equal to 50,000 cubic feet per day may continue to do so without a permit.

These permits are obtained administratively, meaning the operator does not need permission from the Railroad Commissioners, just the Commission staff.[121]

On the flaring regulation page of its web site, the Railroad Commission provides information on administrative flaring permits.[122] The number of permits increased dramatically from 2008 to 2013. In 2008, just 107 permits were issued. In 2013, there were 3,012 permits issued – 28 times the number of permits issued in 2008.

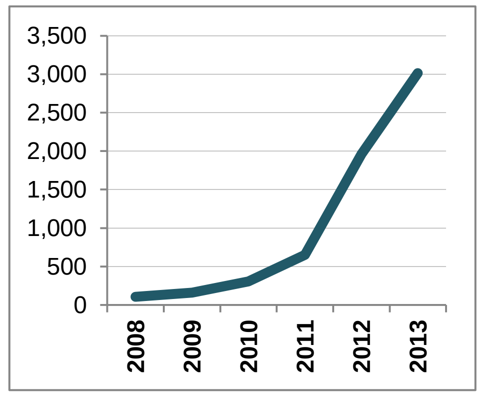


Figure 15. Number of flaring permits issued per year. Years represent the RRC fiscal year (September 1 to August 31).

The Railroad Commission web site does not provide a breakdown of permits issued to oil wells versus gas wells, but the Railroad Commission does say that the majority of flaring permit requests are made by operators wanting to flare natural gas from oil wells, not for flaring from gas wells.[123]

Texas Flaring Exceptions

If operators want to flare beyond the 180-day period mentioned above, they must get permission (in the form of a final order) from the Railroad Commission.[124]

Our analysis of data available from the Railroad Commission shows that from January 2012 through May 2014 the Railroad Commission granted 158 flaring exceptions (2012: 48 exceptions; 2013: 83 exceptions; January through May, 2014: 27 exceptions).[125] When the Railroad Commission grants an exception, the order may cover multiple wells and facilities (e.g., tank batteries).

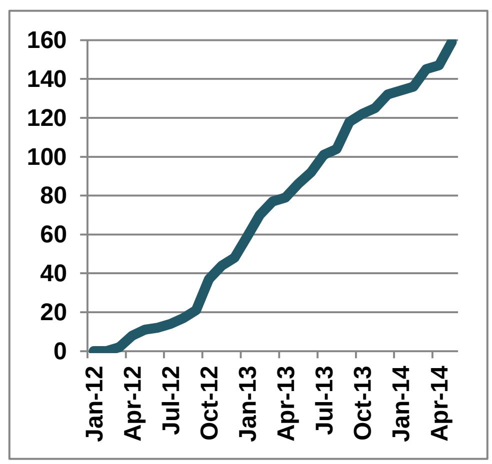


Figure 16. Cumulative flaring exceptions (2012 through May 2014).

More than 60 percent of the exceptions were granted to facilities in the Eagle Ford Shale (97 of 158). The bulk of the other exceptions (45) were from the Permian Basin in West Texas (Spraberry and Wolfbone Trends).

Companies with the largest number of flaring exceptions in Texas

Together, the following companies were responsible for more than 60 percent of all exceptions granted by the Texas Railroad Commission from January 2012 through May 2014: Murphy Exploration and Production (42 exceptions), Clayton Williams (19), EOG Resources (11), Hess (9), Pioneer Natural Resources (9) and Comstock Oil and Gas (8).

Flaring-Related Enforcement Actions: Texas

In 2012, the Railroad Commission began posting information on enforcement actions on its web site.[127] In 2012, there were three alleged violations of Statewide Rule 32 that sets standards for flaring. There were no cases of alleged violations of Rule 32 in 2013 or 2014.

When looking in the Railroad Commission's Severance Database, however, a different picture emerges. The Railroad Commission has the ability to stop production at a well site (sever an oil well or seal a gas well) when violations are found.[128] The first step in the severance process is to send a certified letter to the operator, and if the violation is not resolved the Railroad Commission can order the operator to stop oil or gas production from the well. The Severance Database allows users to search for the number of certified letters sent to operators that are non-compliant with Statewide Rule 32.

Table 8. Number of certified letters to operators that failed to obtain a permit to flare.[126]

	Oil	Gas	Total
2000	39	0	39
2001	27	0	27
2002	32	0	32
2003	31	0	31
2004	33	0	33
2005	21	0	21
2006	3	0	3
2007	0	0	0
2008	1	0	1
2009	0	0	0
2010	0	1	1
2011	1	0	1
2012	0	0	0
2013	59	1	60
2014 (Jan. – June 30)	67	52	119

As seen in Table 8, in the early 2000s, Railroad Commission inspectors were issuing approximately 30 letters per year to operators flaring without a permit. Between 2007 and 2012, however, the number of letters sent to operators was either zero or one per year.

And then, suddenly, in 2013 there was a large increase to 59 instances where operators were found to be flaring without a permit; and within the first five months of 2014 there had already been 60 cases. It's not clear why the numbers have fluctuated so dramatically, the Railroad Commission did not return a call seeking comment.

In 2014 there was a steep rise in the number of gas wells flaring without a permit – in the past, it was primarily oil wells that were illegally flaring gas.

Certain operators have notably poor records for flaring without a permit. In 2013 and the first six months of 2014, Murphy Exploration and Production received 33 severance warning letters, Swift Energy and Comstock received 15 and 14, respectively; Pioneer Natural Resources and Marathon received 12; and EP Energy and Newfield Exploration each received 9 letters. All of the illegal flaring by these companies, except for the wells operated by Comstock, Newfield and some Pioneer wells, occurred in the Eagle Ford Shale.

In Texas, flared gas is not taxed at all,[129] depriving taxpayers of any value from gas that is burned off. Such an exemption seems particularly egregious considering that, as in the Bakken, at least some companies operating in the Eagle Ford Shale are earning hundreds of millions or billions in profit.

Table 9. Estimated taxes paid, based on volumes flared per day (MCF is 1,000 cubic feet).

Top 10 Companies Flaring from the Eagle Ford Shale in 2013	2013 Profits Top Ten Companies Flaring in Eagle Ford Shale
Chesapeake Energy	$894 million[130]
Murphy Oil Corp.	$1.123 billion total and $435 million U.S.[131]
Ep Energy Corp.	$450 million[132]
Comstock Resources, Inc.	$41.029 million[133]
Eog Resources Inc.	$2.2 billion[134]
Carrizo Oil & Gas, Inc.17	$43.683 million[135]
Goodrich Petroleum Co.	$95.186 (loss)[136]
Matador Production Company	$45.1 million[137]
Talisman Energy, Inc. (Subsidiary Talisman Energy Usa, Inc. Operates in Eagle Ford)	$1.175 billion (loss)[138]
Forest Oil Corp.	$73.924 million[139]

Section 6.
The Regulatory Path Forward

How Do We Reduce Flaring from Oil Wells in the Bakken and Eagle Ford Shales?

The most important steps include:

1. Drillers must have a plan in place to limit flaring before drilling begins that will capture all natural gas except that which is technically impossible to collect, and not just "economically Infeasible." North Dakota and Texas prohibit "waste" of oil and natural gas as do several other oil producing states and the federal government.[140]

But flaring of natural gas – except when it is truly impossible to capture – undermines these standards and adds significantly to greenhouse emissions. North Dakota has taken an important step to reduce waste of gas by requiring Bakken drillers to submit gas capture plans before they can receive a permit for new wells. The state's latest rule would also apply oil production limits to wells that flare in excess of new flaring standards that allow for less flaring over time.

Taken together, however, the rules still do not go far enough in preventing flaring of gas that could be recovered. First, the gas capture plan does not necessarily have to capture significant amounts of gas; companies simply have to have a plan before securing a permit. In its latest order, the state exempts from companies' calculation of flared gas all gas flared from the first horizontal well drilled in a non-overlapping spacing unit. The state does not explain why such gas could not be captured or estimate how many wells would be drilled or how much gas would be flared under such an exemption. The state also exempts gas flared from wells that have received an exemption to flare due to "economic infeasibility." However, the state does not explain why such flaring would be technically impossible to prevent. The state also exempts from the amount of natural gas counted as flared any gas emitted during the first 14 days of flowback, the period after a well is hydraulically fractured when injected fluid and gas flow back out of the well. The EPA has found that Reduced Emissions Completion technologies can theoretically capture up to 90 percent of the gas released during flowback if wells are connected to pipelines, suggesting that at least some of this gas could be recovered.[141] Finally, the state sets oil production limits of 100 or 200 barrels of oil per day for wells that flare in excess of the new standards. Yet the state does not say how many wells would face such limits and what percentage of the state's flared gas these wells produce. Lynn Helms, the director of the state's Department of Mineral Resources recently told EnergyWire that based on April oil production figures, he expected a four to five percent reduction in oil production due to the new rules.[142]

Texas does not require drillers to have a gas capture plan before obtaining a permit nor does the state limit flaring to gas that is technically impossible to capture. Texas generally allows flaring for 10 days without a permit and does not require permits for flaring for any period of time if companies flare less than 50,000 cubic feet of natural gas per day. It is unclear why it would be technically impossible to prevent flaring during this time period. When companies flare more than 50,000 cubic feet per day and for longer than ten days, they must receive an administrative permit to do so up to a maximum of 180 days. The issuance of such permits has skyrocketed in recent years, though here, too, it is unclear why companies could not capture their gas instead. In both the Bakken and Eagle Ford, several companies are making hundreds of millions or billions of dollars in profits. It appears that at least some companies could easily make investments in reducing flaring while compensating the public adequately through taxes when gas is flared.

2. Companies should pay taxpayers full market value for gas that is flared with exceptions only for gas that could not technically be recovered such as gas flared in an emergency. When gas is flared and no tax is paid, the resource is completely wasted. Taxpayers receive no value in the present and cannot receive value in the future because the gas is gone. Paying full value would provide a stronger incentive to conserve the gas while reducing pollution and adequately compensating taxpayers for what has been lost: the total value of the gas.

Even with its new gas capture plan and additional order designed to reduce flaring, North Dakota continues to exempt flared gas from the payment of taxes and royalties during the first year of oil production[143] and if driller take several actions including connecting to a pipeline,[144] equipping the well with an electrical generator that uses at least 75% of the produced gas,[145] equipping the well with a system that collects at least 75% of the gas and natural gas liquids for beneficial consumption,[146] equipping the well with other North Dakota Industrial Commission-approved processes that reduce volume of flaring by more than 60 percent[147] and showing that connecting to a pipeline, generating electricity or installing a collection system is economically infeasible. The tax rate on flared gas – if it is taxed – continues to be about two percent of the gas' value – hardly a disincentive to flare.[148]

In Texas, flared gas is not taxed at all.[149] Though, unlike in North Dakota, violations of provisions prohibiting waste of oil or gas will be assessed a fine of up to $10,000 when the violation relates to safety or the prevention or control of pollution and up to $1,000 when the violation does not relate to safety or the prevention or control of pollution. Maximum penalties may be assessed for each day of violation and for each act of violation.[150]

Tax rates in both states for flared gas should be boosted to the full market value of the gas.

3. States should track how much tax drillers pay on flared gas and which drillers are paying. North Dakota does not, preventing the public from knowing how much money the state earns – and loses. Of course, Texas does not either because the state does not tax flared gas.

4. States should track and publicly report the amount of gas flared and vented, and stop relying on self reporting by oil companies. North Dakota, Texas and at least some other oil producing states and the federal government allow companies to self-report the amount of natural gas that is flared or vented. Because such flaring or venting can incur costs and violate regulations, companies have a self-interest to under-report how much gas is flared or vented. Regulators should prevent such a conflict of interest by using technologies and auditing techniques that provide more impartial measurements. Texas should examine whether its reporting exemptions for gas "not readily measured" are excluding significant amounts of gas that are flared or vented.

5. Regulators should tighten enforcement on companies that flare illegally (e.g., without a permit). We saw that in Texas, several companies have been sent warning letters by the Railroad Commission for failing to obtain a flaring permit at many different well sites. Similarly, in North Dakota, two operators repeatedly violated flaring rules. All companies that illegally flare should receive penalties, and repeat offenders should be penalized to the extent of the law.

Endnotes

[1] North Dakota Pipeline Authority, A Detailed Look at Natural Gas Gathering (Oct. 21, 2013), http://northdakotapipelines.com/natural-gas-study/, at 1. U.S. Energy Information Administration, Trends in Eagle Ford Drilling Highlight the Search for Oil and Natural Gas Liquids (Nov. 3, 2011), http://www.eia.gov/todayinenergy/detail.cfm?id=3770.

[2] Earthworks focused on health effects from air emissions associated with oil and gas drilling in the Eagle Ford Shale in Reckless Endangerment (Sept. 19, 2013), http://www.earthworksaction.org/library/detail/reckless_endangerment_in_the_eagle_ford_shale#.U-oen0gwLt8.

[3] **Bakken & Eagle Ford data from:** U.S. Energy Information Administration (EIA). Drilling Productivity Report Data (July 14, 2014). http://www.eia.gov/petroleum/drilling/xls/dpr-data.xlsx. Note: EIA's Bakken statistics include production from North Dakota and Montana Bakken wells. **US data from:** U.S. Energy Information Administration, Petroleum & Other Liquids, U.S. Field Production of Crude Oil. Accessed July 23, 2014 at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPUS2&f=M.

[4] See footnote 3.

[5] U.S. Energy Information Administration, Drilling Productivity Report Data (June 9, 2014), http://www.eia.gov/petroleum/drilling/xls/dpr-data.xlsx. Note: EIA's Bakken statistics include production from North Dakota and Montana Bakken wells.

[6] North Dakota Department of Mineral Resources, North Dakota Monthly Bakken Oil Production Statistics. Accessed online June 23, 2014 at https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf.

[7] The production data that we used to determine oil and gas produced and gas flared from Bakken wells did not specify if the well was considered and "oil", "gas" or "oil and gas" well. (Source: State Wide Production Data. NDIC web site. Note: this is a premium (paid) service. https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp) But when reviewing the data, we found that there were some Bakken wells that produced only oil, not gas.

[8] Eagle Ford Shale **Oil fields:** Cherokee; Cypress Landing; and Aguila Vado. **Natural gas fields:** Apache Ranch; De Witt; Eagle Ridge; Gates Ranch; Giddings, South; Hawkville; and Junco. **Oil and gas fields:** Sugarkane, Fashing; Giddings; Southern Bay; Briscoe Ranch; Eagleville (Eagle Ford-2); and Eagleville (Eagle Ford-2). Railroad Commission of Texas, Eagleford Fields and Counties – March 2013. Accessed June 23, 2014 at http://www.rrc.state.tx.us/eagleford/Eagle_Ford_counties_201312.xls.

[9] **How we calculated gas produced from Bakken wells:** 1) We downloaded the North Dakota statewide production data for June 2014. (https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp). To narrow the data to "Bakken" wells we selected wells in the Bakken, Three Forks and Sanish Pools. We used these three pools because they are the ones NDIC uses to calculate its Monthly Bakken Oil Production Statistics (see: https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf). We then tallied the "Mcf Gas", i.e., gas produced, from all of the Bakken wells.

How we calculated gas produced from Eagle Ford Shale wells: We used the method described in footnote 26. But instead of adding up the volumes of flared gas, we added the volumes of casinghead gas (for EFS oil wells) or GW, i.e., gas well gas (for EFS gas wells).

[10] North Dakota Pipeline Authority. Oct. 21, 2013. A Detailed Look at Natural Gas Gathering. p. 1. http://northdakotapipelines.com/natural-gas-study/. Clifford Kraus, Industry in North Dakota to Cut Flared Natural Gas, New York Times (Jan. 30, 2014), http://www.nytimes.com/2014/01/30/business/energy-environment/industry-in-north-dakota-promises-to-reduce-flared-natural-gas.html?_r=1. Vicki Vaughan, Program in Eagle Ford Aims to Curb Natural Gas Flaring, Houston Chronicle (May 23, 2012), http://www.chron.com/business/article/Program-in-Eagle-Ford-aims-to-curb-natural-gas-3581427.php. Venting gas (releasing it unburned) is prohibited under North Dakota regulations and disfavored under Texas regulations because it can contain toxic contaminants such as deadly hydrogen sulfide. See N.D. Admin. Code § 43-02-03-45 and 16 Tex. Admin. Code Rule § 3.32 (e) (1)-(e) (4); § 3.36. The major component of raw natural gas, methane, is also a much more powerful greenhouse gas than carbon dioxide.

[11] Ben Winkley, Energy Journal: Flare-Up in North Dakota, Wall Street Journal (Aug. 1, 2013) (reporting that "low gas prices, remote locations and the time and expense of developing pipelines" have contributed to the high rate of flaring). Ajay Makan and Ed Crooks, Shale Gas Boom Now Visible from Space, Financial Times (Jan. 27, 2013), http://www.ft.com/cms/s/0/d2d2e83c-6721-11e2-a805-00144feab49a.html#axzz35JVMiFXy (reporting that low natural gas prices have contributed to the flaring). Clifford Kraus, In North Dakota Flames of Wasted Natural Gas Light the Prairie, New York Times (Sept. 27, 2011) at A1, http://www.nytimes.com/2011/09/27/business/energy-environment/in-north-dakota-wasted-natural-gas-flickers-against-the-sky.html?pagewanted=all&_r=0 (reporting that the combination of high oil prices and low natural gas prices has created a rush to drill for oil with less regard for capturing the natural gas).

[12] In October 2013, oil from the Bakken was worth 0.0000147 per British Thermal Unit. See North Dakota Industrial Commission, Oil and Gas Division, Director's Cut (Dec. 13, 2013), https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-12-13.pdf (reporting that the value of Bakken oil was $85.16 per barrel). U.S. Energy Information Administration, Energy Units and Calculators Explained, http://www.eia.gov/energyexplained/index.cfm?page=about_energy_units (reporting that there were 5,800,000 British Thermal Units per barrel of oil). Meanwhile, natural gas from the Bakken was worth 0.0000036 per British Thermal Unit. See North Dakota Industrial Commission, Oil and Gas Division, Director's Cut (Dec. 13, 2013),

https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-12-13.pdf (reporting that the price of natural gas at Northern Border at Watford City was $3.67 per thousand cubic feet). U.S. Energy Information Administration, Energy Units and Calculators Explained, http://www.eia.gov/energyexplained/index.cfm?page=about_energy_units (reporting that there were 1,025,000 British Thermal Units per thousand cubic feet of natural gas). Therefore, the value of the gas was about 25 percent of the value of the oil on a per BTU basis.

[13] Electronic mail communication with David Hughes, geoscientist, fellow at the Post Carbon Institute and former scientist with the Geological Survey of Canada (June 30-July 1, 2014).

[14] North Dakota Pipeline Authority, North Dakota Natural Gas: A Detailed Look at Natural Gas Gathering (Oct. 21, 2013), http://ndpipelines.files.wordpress.com/2012/07/ndpa-detailed-look-at-gas-gathering-2013.pdf, at 2. North Dakota Industrial Commission, Oil and Gas Division, Director's Cut (Oct. 15, 2013), https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-10-15.pdf. The nonprofit organization Ceres reported that, including liquids, natural gas produced from the Bakken shale could be as valuable as $13.50 per thousand cubic feet. Ceres, Flaring Up: North Dakota Natural Gas Flaring More than Doubles in Two Years (July 2013), http://www.ceres.org/resources/reports/flaring-up-north-dakota-natural-gas-flaring-more-than-doubles-in-two-years/view, at 6.

[15] See footnote 9.

[16] Government Accountability Office, Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases (Oct. 29, 2010), http://www.gao.gov/products/GAO-11-34.

[17] See footnote 9.

[18] See footnote 9.

[19] U.S. Environmental Protection Agency, Office of the Inspector General, EPA Needs to Improve Air Emissions Data for the Oil and Natural Gas Production Sector, http://www.epa.gov/oig/reports/2013/20130220-13-P-0161.pdf, at 2-3, 14.

[20] IPCC Fifth Assessment Report, Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (accepted September 26, 2013). http://www.ipcc.ch/report/ar5/, at 714.

[21] The Texas Railroad Commission keeps records on gas flared from gas wells, oil wells (casinghead gas), and gas processing plants (cycling, gasoline other gas plant operations). (Data from http://www.rrc.state.tx.us/oil-gas/research-and-statistics/production-data/monthly-summary-of-texas-natural-gas/) **Gasoline plant:** a plant/facility extracting liquid hydrocarbons from natural gas. **Cycling plant:** a plant/facility that extracts dry gas from wet gas and returns dry gas to the oil reservoir for pressure maintenance purposes. **Other plants:** include compressors, drip stations, scrubbers, separators, dehydrators, etc. (Source: Railroad Commission of Texas. 2013. "Oil Refinery & Natural Gas Plant Reports." http://www.rrc.state.tx.us/education/seminars/31-GasPlantsandRefineriesHandouts.pdf

The North Dakota Industrial Commission keeps records on gas flared from and oil wells, and gas plants. **Oil and gas well data** available at: "State Wide Production Data" (which provides a list of all wells, and their oil, gas, water, flared gas and other production data in the selected month). **ND gas plant flaring data** are available at: "Monthly Gas Plant Volumes" (which provides historical monthly production data, including flaring volumes, on a plant-by-plant basis. https://www.dmr.nd.gov/oilgas/feeservices/gasplants.asp)

[22] RRC web site: "Monthly Summary of Texas Natural Gas." Annual Monthly Gas Summaries for 2010 - 2013. http://www.rrc.state.tx.us/oil-gas/research-and-statistics/production-data/monthly-summary-of-texas-natural-gas/

[23] **North Dakota gas plant data for 2013:** We obtained gas plant flaring data for each month in 2013, and then added all monthly data to obtain a value for the year. Reporting gas plants flared 1.3 bcf and 8.2 bcf in 2010 and 2013, respectively. (North Dakota Industrial Commission (NCID). Monthly Gas Plant Volumes, https://www.dmr.nd.gov/oilgas/feeservices/gasplants.asp. NOTE: the data are accessible only through the paid Premium subscription).

Flaring data for all wells in 2013: For each month of 2013 we downloaded state wide production data for all wells and added the volume of gas flared for all wells to derive a total flaring volume for the month. Then we added all monthly data to obtain a value for the year. Oil and gas wells flared 31 and 106 bcf in 2010 and 2013, respectively. **(NDIC.** State Wide Production Data. (https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp)

North Dakota Industrial Commission. Monthly Gas Plant Volumes, https://www.dmr.nd.gov/oilgas/feeservices/gasplants.asp NOTE: the data are accessible only through the paid Premium subscription).

[24] See footnote 22. We found that in 2010 flared casinghead gas was 7 bcf and gas plants flared 33 bcf; but in 2011 flared casinghead gas jumped to 19 bcf, and gas flared from gas plants fell to 17 bcf.

[25] See footnote 23. We found that gas flared from gas plants was 1.3 bcf in 2010 and 8.2 bcf in 2013, while gas flared from oil and gas wells in North Dakota was 31 bcf and 106 bcf for 2010 and 2013, respectively. So the percentages of gas flared from gas plants was 4 and 8 percent of gas flared from North Dakota wells in 2010 and 2013, respectively.

[26] **How we calculated flaring volume for Eagle Ford Shale (EFS) wells:**

1) Determined EFS fields: We looked at all of the Eagle Ford Shale fields (http://www.rrc.state.tx.us/eagleford/Eagle_Ford_counties_201312.xls) that had reported volumes of casinghead gas (these included oil fields, natural gas fields, and oil and gas fields). These included: Aguila Vado; Briscoe Ranch; Cherokee; Cypress

Landing; De Witt; Eagle Ridge; Eagleville/Eagle Ford 1; Eagleville/Eagle Ford 2; Fashing; Gates Ranch; Giddings; Hawkville; Southern Bay; and Sugarkane). **2) Determined flaring data for each well in EFS fields:** We obtained data on flaring of casinghead gas from each well in each EFS field using the RRC online "Production Query" (http://webapps2.rrc.state.tx.us/EWA/productionQueryAction.do). We did separate searches for all of the EFS fields listed above, and downloaded all wells from these field. Flaring data is found by clicking on the lease name, then disposition details. Disposition Code 4 represents flared casinghead gas. We added the monthly flaring data for all months in a particular year to come up with the annual volume flared from the lease. We repeated that step for each year of interest.

[27] See footnote 22.

[28] See footnote 23.

How we calculated flaring volumes for Bakken wells: 1) To find flaring volumes we downloaded the North Dakota statewide production data for a specific month. (https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp). To narrow the data to "Bakken" wells we selected wells in the Bakken, Three Forks and Sanish Pools. We used these three pools because they are the ones NDIC uses to calculate its Monthly Bakken Oil Production Statistics (see: https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf).We added MCF flared for all Bakken wells for each month. 4) We repeated this for every month in 2013. 5) We tallied all months to come up with total volume of gas flared from Bakken wells in 2013.

[29] See footnote 8 to find out how we determined monthly gas flared from the Bakken. The value of flared gas was derived by multiplying the total monthly volume of flared gas by the average monthly price of natural gas delivered to Northern Border at Watford City (as reported by NDIC Director, L. Helms in the monthly "Director's Cut" available at: https://www.dmr.nd.gov/oilgas/directorscut/directorscutarchive.asp). Note: we did not include January, February and March 2010 data, as there were no natural gas prices reported by NDIC for those months.

[30] See footnote 20.

[31] See footnote 26. Also, we tracked the volume of gas produced from "oil" fields vs. "natural gas" fields. For the "oil and gas" fields, we conducted two queries, one for oil leases and one for gas wells (the initial search criteria allows users to select Oil Leases, Gas Wells or Both). We found that EFS oil wells flared 29 bcf of the 34 bcf flared from all EFS wells in 2013.

[32] U.S. Energy Information Administration, Shale Gas Production, http://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm.

[33]There are 98.4 trillion British Thermal Units in in 96 billion cubic feet of natural gas. See U.S. Energy Information Administration, Energy Units and Calculators *Explained,* http://www.eia.gov/energyexplained/index.cfm?page=about_energy_units (reporting that each cubic foot of natural gas contains 1,025 BTUs. This amount of gas emits 11,512,800,000 pounds of carbon dioxide when burned. See Energy Information Administration, Natural Gas Explained, Natural Gas and the Environment, http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_environment (reporting that "about 117 pounds of carbon dioxide are produced per million Btu equivalent of natural gas"). Burning about 607,535,620 gallons of gasoline would generate the same amount of carbon dioxide emissions. See U.S. Energy Information Administration, Frequently Asked Questions, How Much Carbon Dioxide is Produced by Burning Gasoline and Diesel Fuel? http://www.eia.gov/tools/faqs/faq.cfm?id=307&t=11 (reporting that a gallon of gasoline with 10 percent ethanol emits about 18.95 pounds of carbon dioxide). More than 90 percent of U.S. gasoline contains 10 percent ethanol. See U.S. Environmental Protection Agency, Fuels and Fuel Additives, E15: Frequently Asked Questions, http://www.epa.gov/otaq/regs/fuels/additive/e15/e15-faq.htm. The average light duty vehicle in the U.S. used 530 gallons of gasoline in 2011, the latest available data. Light duty vehicles include cars, vans, light trucks and sport utility vehicles. See U.S. Department of Transportation, Federal HIghway Administration, Annual Vehicle Distance Traveled in Miles and Related Data - 2011 (1) by Highway Category and Vehicle Type, www.fhwa.dot.gov/policyinformation/statistics/2011/xls/vm1.xlsx. Dividing 607,535,620 gallons of gasoline by 530 gallons per vehicle equals 1,146,294 vehicles.

[33] Energy Information Administration, Natural Gas, Natural Gas Consumption by End Use, North Dakota (reporting that residential customers used 12.167 billion cubic feet of natural gas in 2013), http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SND_a.htm.

[34] There are 30.34 trillion British Thermal Units in in 29.6 billion cubic feet of natural gas. See U.S. Energy Information Administration, Energy Units and Calculators *Explained,* http://www.eia.gov/energyexplained/index.cfm?page=about_energy_units (reporting that each cubic foot of natural gas contains 1,025 BTUs. This amount of gas emits 3,549,780,000 pounds of carbon dioxide when burned. See Energy Information Administration, Natural Gas Explained, Natural Gas and the Environment, http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_environment (reporting that "about 117 pounds of carbon dioxide are produced per million Btu equivalent of natural gas"). Burning 187,323,483 gallons of gasoline with 10 percent ethanol would generate the same amount of carbon dioxide emissions. See U.S. Energy Information Administration, Frequently Asked Questions, How Much Carbon Dioxide is Produced by Burning Gasoline and Diesel Fuel? http://www.eia.gov/tools/faqs/faq.cfm?id=307&t=11 (reporting that a gallon of gasoline with 10 percent ethanol emits about 18.95 pounds of carbon dioxide). More than 90 percent of U.S. gasoline contains 10 percent ethanol. See U.S. Environmental Protection Agency, Fuels and Fuel Additives, E15: Frequently Asked Questions, http://www.epa.gov/otaq/regs/fuels/additive/e15/e15-faq.htm. The average light duty vehicle in the U.S. used 530 gallons of gasoline in 2011, the latest available data. Light duty vehicles include cars, vans, light trucks and sport utility vehicles. See U.S. Department of Transportation, Federal HIghway Administration, Annual Vehicle Distance Traveled in Miles and Related Data - 2011 (1) by Highway Category and Vehicle Type, www.fhwa.dot.gov/policyinformation/statistics/2011/xls/vm1.xlsx. Dividing 187,323,483 gallons of gasoline by 530 gallons per vehicle equals 353,441 vehicles.

[35] For more information see: Vazquez, A and Tovar, D. 2013. "Assessment of flare stack efficiency of emission control of greenhouse gases in the oil and gas industry," International Journal of Information Technology and Business Management. http://www.jitbm.com/JITBM%2015th%20volume/8%20Green%20House%20-%20Enviornment%20Safety.pdf; Ventura County Air Pollution Control District. 2001. Toxic Emission Factors for Combustion Process (Natural Gas and Diesel). http://www.aqmd.gov/docs/default-source/permitting/toxics-emission-factors-from-combustion-process-.pdf?sfvrsn=0c; and Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. "Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p. 1614.

[36] For example, it has been estimated that production flares may contribute approximately 4 and 7 % of VOCs and NOx, respectively, of the emissions from oil and gas development in the Eagle Ford Shale. NOx and VOCs are ozone precursors. (Source: Alamo Area Council of Govenments. Oil and Gas Emission Inventory, Eagle Ford Shale - Technical Report. See Table 9-2. http://www.aacog.com/DocumentCenter/View/19069)

[37] 16 Tex. Admin. Code Rule § 3.32 (d) (1) (F).

[38] 16 Tex. Admin. Code Rule § 3.32 (d) (1) (G).

[39] N.D. Admin. Code § 43-02-03-44, 43-02-03-45, 43-02-03-52.1.

[40] **Bakken statistic:** The NDIC does not label its wells "oil" or "gas" wells. So to determine the volume of gas flared from Bakken "gas wells" (which included wells from the Bakken, Three Forks and Sanish Pools) we looked at all Bakken wells that only produced gas, i.e., produced no oil, in each month of 2013 (See footnote 28). We then tallied the volume of gas from such wells. We found that these wells flared 0.227 bcf of gas, which is less than 0.3 % of the 96 bcf of gas flared from all Bakken wells in 2013.

EFS statistic: See footnote 26. We separated out the flaring data for "oil fields" and "natural gas" fields. And for "oil and gas fields" we determined flaring from oil leases and gas wells separately by conducting two queries – one for "oil leases" and one for "gas wells". (The RRC Production Data query allows users to set the initial search criteria for Oil Leases, Gas Wells or Both. See: http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do). We found that gas wells flared 4.4 bcf of the 34 bcf flared from all Eagle Ford Shale wells.

[41] We used the Bakken flaring data for each month of 2013 (as described in footnote 28). 1) The statewide production data that provided flaring volumes does not include company information. So to find out which companies operated the Bakken wells we downloaded the NDIC Well Index file (https://www.dmr.nd.gov/oilgas/feeservices/flatfiles/flatfiles.asp Accessed June 17, 2014). The NDIC Well Index file data include company information. By using the Well File number, we were able to add company information to each of the Bakken wells. 2) We were then able to filter the data to determine which companies had the most wells in the Bakken. 3) For the top 20 companies we added up the flaring volumes on a monthly basis; then added up the flaring volumes for all of the months in 2013 to derive a total volume flared by that company for the year.

[42] We used the EFS flaring data (as described in footnote 24)**.** Data downloaded in March 2014. The RRC lease data that we downloaded did not include operator, so we added a column and inserted the operator name, as well as the flaring volumes. That enabled us to filter the data by operator. We then tallied the specific volumes flared by operator for 2013.

[43] These companies were: Chesapeake Operating; Murphy Expl. & Production; EP Energy E&P; Comstock Oil and Gas; Carrizo (Eagle Ford) LLC; Goodrick Petroleum flared increasingly large volumes of gas from 2010 to 2013. EOG Resources and Matador Production Company both showed decreases in volumes flared from 2012 to 2013. (We used the method described in footnote 24 to determine flaring volumes for the top companies for 2010, 2011 and 2012.)

[44] Due to the format of the North Dakota data, it was time-consuming to determine volumes flared by company. So we confined our analysis to 12 months.

[45] The large jump in volume of gas flared by Hess in December is likely due to the fact that in late November 2013 a Hess processing plant (Tioga) shut down to allow work on the plant's expansion (See: North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division, Director's Cut (Jan. 14, 2014), https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2014-01-14.pdf). So some Hess wells that would have otherwise shipped their gas to that plant would have had to flare the gas instead.

[46] Hess Corporation, How We Operate, Unconventional Resources, Air Emissions. http://www.hesscorporation.com/media/csr_2011/2011site/operate_24.html. Accessed June 30, 2014. In May 2014, Hess reiterated its goal to reduce its flaring in North Dakota to below 10 percent, but was less specific on a time frame, stating its intention to achieve this goal "in coming years." Josh Wood, Hess Shows Off Upgraded Tioga Gas Plant, Bloomberg Business Week, http://www.sfgate.com/business/energy/article/Hess-shows-off-upgraded-Tioga-gas-plant-5489779.php.

[47] **How we arrived at our numbers.** 1) Downloaded the statewide production data for March 2014. North Dakota Industrial Commission, Department of Mineral Resources, Division of Oil and Gas, State Wide Production Data, https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp. (Note: this is a paid service.) 2) Downloaded the well files (well index). North Dakota Industrial Commission, Department of Mineral Resources, Division of Oil and Gas, Well Index and Flat Files, https://www.dmr.nd.gov/oilgas/feeservices/flatfiles/flatfiles.asp. (Note: this is a premium (paid) service.) 3) Filtered well files to find all Hess wells in the Bakken and Three Forks Pools. 4) Matched all of these wells (based on File number), with the same wells in the Statewide production data. 5) Added MCF flared for all wells. 6) Added MCF produced for all wells. 7) Calculated percentage of gas flared by dividing total gas flared by Hess' Bakken wells by total gas produced by Hess' Bakken wells, and multiplied by 100.

[48] We determined flaring volumes using the same method as described in footnote 47.

[49] Richard Nemec, Kodiak Looks to Curb Flaring, NGI's Shale Daily (May 20, 2014), http://www.naturalgasintel.com/articles/98431-bakken-producer-kodiak-looks-to-curb-flaring.

[50] U.S. Securities and Exchange Commission, Continental Resources Inc., Form 10-K for 2012, at 25, filed Feb. 28, 2013.

[51] Clifford Kraus, In North Dakota Flames of Wasted Natural Gas Light the Prairie, New York Times (Sept. 27, 2011) at A1, http://www.nytimes.com/2011/09/27/business/energy-environment/in-north-dakota-wasted-natural-gas-flickers-against-the-sky.html?pagewanted=all&_r=0.

[52] See footnote 47.

[53] N.D. Cent. Code § 38-08-01. N.D. Admin. Code § 43-02-03-06.

[54] Earthworks, Breaking All the Rules (Sept. 2012), http://www.earthworksaction.org/files/publications/FINAL-US-enforcement-sm.pdf, at 25.

[55] Mike Soraghan, Oil and Gas Spills: Many Mishaps Among Drillers, But Few Fines, EnergyWire (July 15, 2013) (subscription only).

[56] N.D. Cent. Code § 38-08-06.4.

[57] N.D. Cent. Code § 38-08-06.4 (2) (a).

[58] N.D. Cent. Code § 38-08-06.4 (2) (b).

[59] N.D. Cent. Code § 38-08-06.4 (2) (c).

[60] N.D. Cent. Code § 38-08-06.4 (2) (d).

[61] N.D. Cent. Code § 38-08-06.4 (2) (e).

[62] N.D. Cent. Code § 38-08-06.4 (4).

[63] In addition, drillers can avoid taxes – but not royalties – on gas for two years and 30 days from the time of first production if at least seventy-five percent of the gas produced from the well is used to power an electric generator or if at least seventy-five percent of the gas and natural gas liquids volume is used for "beneficial consumption" including for production of petrochemicals, fertilizer and conversion to liquid fuels. N.D. Cent. Code § 57-51-02.6.

[64] U.S. Energy Information Administration. Shale Gas Production. http://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm (EIA reports gas production in billion cubic feet. 133,800,000 MCF is the equivalent of 133 billion cubic feet of gas).

[65] **How we calculated the data:** 1) To determine which wells started producing oil and/or gas in 2009, 2010, 2011 or 2012, we looked up information on the Initial Production Test (IPT) date for Bakken wells. This information is available in the Well Index database, which we downloaded from the NDIC web site in June 2014. https://www.dmr.nd.gov/oilgas/feeservices/flatfiles/flatfiles.asp

(Note: access to the Well Index requires a paid Premium Subscription). Bakken wells included wells in the Bakken, Three-Forks, Bakken-Three Forks and Sanish pools, as per NDIC's classification of Bakken wells. See "Historical Monthly Bakken Oil Production Statistics." https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf 2) For each well with an IPT date in 2009, we then determined the volume of gas flared in each well's first year of production by adding the volume of gas flared in the first 12 months after that well first started to produce oil and/or gas. (Flaring data were obtained by searching for each well's production history data (https://www.dmr.nd.gov/oilgas/feeservices/getwellprod.asp?), using the well's Well File Number.) 3) To come up with a total for 2009, we added the volumes for all wells with and IPT date in that year. 4) We repeated steps 1) through 3) for 2010, 2011 and 2012.

[66] This is the average of five tax periods (7/2008 – 6/2009: $0.1476; 7/2009 – 6/2010: $0.1831; 7/2010 – 6/2011: $0.0914; 7/2011 – 6/2012: $0.1112; and 7/2012 – 6/2013: $0.1143). Tax rate data from: Office of State Tax Commissioner (North Dakota). Gas tax rate table. Available at: http://www.nd.gov/tax/oilgas/pubs/gas-rate.html Accessed July 30, 2014.

[67] For wells that first started producing gas in 2009, 2010, 2011 or 2012, the volume of gas flared in their first year of production was 133,789,438 MCF. This gas was exempt from North Dakota's gas tax. Multiplied by a tax rate of $0.1295, the tax revenues would have been $17,325,732.

[68] N.D. Cent. Code § 38-08-06.4 (2) (c)-(e).

[69] Phone conversation with representative of North Dakota Tax Department (Mar. 24, 2014). Electronic mail communication with representative of Department of Mineral Resources (July 30, 2014).

[70] North Dakota Pipeline Authority, May 2014 Monthly Update, http://northdakotapipelines.com/directors-cut/, at 7.

[71] This chart includes all wells that started producing gas in 2009. To find out how we calculated the data for this chart, see the footnote 62.

[72] Letter from Todd L. Holweger, North Dakota Department of Mineral Resources, Oil and Gas Division, Permit Manager, to oil and natural gas operators (May 9, 2014).

[73] North Dakota Industrial Commission, Case No. 22058, Order No. 24665 (July 1. 2014).

[74] See footnote 70, at 4.

[75] See footnote 70, at 5.

[76] Howarth et al. Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations, Climatic Change (2011) 106: 679-690, at 682 (citing U.S. Environmental Protection Agency, Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document (2010), http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf, at 87).

[77] See footnote 70, at 5.

[78] See footnote 70, at 5.

[79] Mike Lee, N.D. Likely to Use Penalties to Cut Gas Flaring, Regulator Says, EnergyWire (July 15, 2014), http://www.eenews.net/energywire/stories/1060002838/search?keyword=north+dakota+flaring (subscription only).

[80] In its 2013 Report, Ceres stated that North Dakota has set an unofficial goal of reducing flaring to 10 percent gas production by 2020. (Flaring Up: North Dakota Natural Gas Flaring More Than Doubles in Two Years, Ceres, http://www.ceres.org/resources/reports/flaring-up-north-dakota-natural-gas-flaring-more-than-doubles-in-two-years/view, at 10). And a proposal by the North Dakota Petroleum Council Flaring Task Force similarly set a goal of flaring less than 10% of gas by 2020, and ultimately reducing flaring to 5% of gas produced. (Lee, M. Jan. 30, 2014. "N.D. oil drillers call for regulation, more pipes to reduce gas." E&E.)

[81] Amy Dalrymple, Gas Plant Opening Marks 'New Era' for N.D. Industry, Oil Patch Dispatch (May 19, 2014) http://oilpatchdispatch.areavoices.com/2014/05/19/gas-plant-opening-marks-new-era-for-n-d-.

[82] Ceres, Flaring up: North Dakota Natural Gas Flaring More Than Doubles in Two Years, July 2013, http://www.ceres.org/resources/reports/flaring-up-north-dakota-natural-gas-flaring-more-than-doubles-in-two-years/view.

[83] Fielden, S. Sept 10, 2012. "Why will Bakken flaring not fade away"? Oil and Gas Financial Journal. http://www.ogfj.com/articles/2012/09/why-will-bakken-flaring-not-fade-away.html

[84] Total gas produced in the state was derived by adding MCF Gas (gas produced) from all wells listed in the North Dakota Industrial Commission statewide production data (https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp, downloaded June 2, 2014). These data are reported on a monthly basis, so we downloaded all data for all months in each year, and added the totals for each month to come up with the annual volume of produced gas. Note, these values differ from Industrial Commission data (Gas production totals by formation for the year: G-2012, G-2011, G-2010 https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp) We believe our data represent the more accurate number, as they are based on the most up-to-date NDIC data.

[85] Clifford Kraus, Industry in North Dakota to Cut Flared Natural Gas, New York Times (Jan. 29, 2014), http://www.nytimes.com/2014/01/30/business/energy-environment/industry-in-north-dakota-promises-to-reduce-flared-natural-gas.html?_r=1

[86] N.D. Cent. Code § 38-08-06.4.

[87] N.D. Admin. Code § 43-02-03-60.2

[88] This information came from the North Dakota Industrial Commission web site, which allows users to search for Orders issued by the Commission. Users must have a paid "Premium" subscription to access this information.

[89] We searched ND Industrial Commission Orders for those containing "38-08-06.4," which is the Section of the North Dakota Century Code that allow for flaring exemptions (http://www.legis.nd.gov/cencode/t38.html). It is possible, but unlikely, that orders related to flaring exemptions would be issued without mentioning NDCC Section 38-08-06.4 in the Order. (Orders are accessible through the NDIC web site if you have a paid Premium Subscription. https://www.dmr.nd.gov/oilgas/subscriptionservice.asp)

[90] N.D. Admin. Code § 43-02-03-31 (allowing operators to keep some well data confidential for six months). Non-confidential wells are those that are not covered by this six-month blanket.

[91] North Dakota Pipeline Authority, North Dakota Natural Gas: A Detailed Look at Natural Gas Gathering, (Oct. 21, 2013), http://northdakotapipelines.com/natural-gas-study/, at 5.

[92] The North Dakota Industrial Commission found that Baytex erred in its production tax calculation and the actual amount was approximately $19,550, not $96,400. So the total net value of the surplus gas reserves of the Hall #3-161-98H well to the working interest owners, after deducting royalty and production taxes, is approximately $650,950.

[93] North Dakota Industrial Commission, Order 18243. https://www.dmr.nd.gov/oilgas/feeservices/ord/comm/18/or18243.pdf#search=%2206.4%22.

[94] North Dakota Industrial Commission Order 13319. https://www.dmr.nd.gov/oilgas/feeservices/ord/comm/13/or13319.pdf#search=%2206.4%22.

[95] See footnote 91.

[96] **Volume of crude per day:** In July the well produced 2,075 barrels of oil, or an average of 69 barrels per each day of the month. (Source: Jack Pennington 21-28H Scout Ticket (File 16778), Production History. https://www.dmr.nd.gov/oilgas/feeservices/getscoutticket.asp)

Price of North Dakota crude in July 2009 was $56/barrel (according to US Energy Information Administration data: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F002038__3&f=M)

Oil revenues per day = 69 barrels per day x $56/barrel = $3,873.

[97] **Volume of natural gas per day:** In July the well flared/vented 927,000 cubic feet of gas, or an average of 31,000 cubic feet per day. (Source: Jack Pennington 21-28H Scout Ticket (File 16778), Production History. https://www.dmr.nd.gov/oilgas/feeservices/getscoutticket.asp)

Tax per day = ND tax rate of $0.18 x 31 MCF = $5.70. (ND tax rate from: http://www.nd.gov/tax/oilgas/pubs/gas-rate.html)

Price of wellhead natural gas in ND in July 2009 was $3.74 per thousand cubic feet, i.e., MCF (according to US Energy Information Administration data: http://www.eia.gov/dnav/ng/hist/na1140_snd_3a.htm)

Royalty rate of 20% estimated based on Baytex example. We realize that royalty rates can vary dramatically, so this is just a rough estimate.

[98] E.g., see Order 13301. Hess Corp., estimated a loss of $83,000 if they had to build a pipeline. Since the order was issued in July 2009, the well has flared 116,486 MCF of gas. Other examples include: Order 23737 (XTO Energy, loss of $62,525); Order 16618 (Oasis Pet., loss of $45,000), Order 16560 (Oasis Pet., loss of $64,000), and others. (Orders can be found on the NDIC web site: https://www.dmr.nd.gov/oilgas/feeservices/ordersearch.asp. NOTE: You must have a paid Premium Subscription to access these files)

[99] Elisabeth Dilts and Sabina Zawadzki, Bakken Crude Breakeven Prices as Low as $58/bbl in 2014 – Report, Reuters (April 2, 2014), http://www.reuters.com/article/2014/04/02/energy-crude-bakken-idUSL1N0MU21Z20140402.

[100] U.S. Securities and Exchange Commission, Hess Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/4447/000119312514077565/d652042d10k.htm, at 20.

[101] U.S. Securities and Exchange Commission, Kodiak Oil & Gas Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=9427152&type=HTML&symbol=KOG&companyName=Kodiak+Oil+&+Gas+Corp.&formType=10-K&dateFiled=2014-02-27, at 42.

[102] Statoil, Annual Report on Form 20-F, filed with U.S. Securities and Exchange Commission for fiscal year ended Dec. 31, 2013, http://www.statoil.com/no/InvestorCentre/AnnualReport/AnnualReport2013/Documents/DownloadCentreFiles/01_KeyDownloads/AnnualReport20-F.pdf, at 4 (reporting net income of 39.2 billion Krone, the Norweigian currency; the Krone was worth $6.145 dollars as of Jan. 24, 2014; see Bloomberg, U.S. Dollar-Norweigian Krone Exchange Rate, http://www.bloomberg.com/quote/USDNOK:CUR/chart; 39.2 billion Krone was the equivalent of approximately $6.4 billion).

[103] U.S. Securities and Exchange Commission, ExxonMobil Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/34088/000003408814000012/xom10k2013.htm, at 36, 40. Upstream relates to production of oil and gas rather than the processing or downstream operations. See Schlumberger, Oilfield Glossary, Upstream, http://www.glossary.oilfield.slb.com/en/Terms/u/upstream.aspx.

[104] U.S. Securities and Exchange Commission, Halcón Resources Corp., Form 10-K filed with U.S. Securities and Exchange Commission for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/1282648/000104746914001420/a2218408z10-k.htm, at 45.

[105] U.S. Securities and Exchange Commission, EOG Resources, Inc., Form 10-K filed with U.S. Securities and Exchange Commission for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/821189/000082118914000007/eogform10-k.htm, at 34.

[106] U.S. Securities and Exchange Commission, Marathon Oil Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/101778/000010177814000014/mro-20131231x10k.htm, at 34, 111.

[107] U.S. Securities and Exchange Commission, Continental Resources, Form 10-K for fiscal year ended Dec. 31, 2013, Annual Report, http://media.corporate-ir.net/media_files/IROL/19/197380/CLR_2013_Annual_Report.pdf, at 1.

[108] U.S. Securities and Exchange Commission, Whiting Petroleum Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/1255474/000125547414000005/form10-k.htm, at 49.

[109] U.S. Securities and Exchange Commission, QEP Resources Inc., Form 10-K, for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/1108827/000110882714000016/qep-20131231x10k.htm, at 43 (QEP Resources is the holding company for QEP Energy).

[110] Based on the July rate for each year according to the North Dakota Tax Department web site: http://www.nd.gov/tax/oilgas/pubs/gas-rate.html.

[111] North Dakota Office of State Tax Commissioner, North Dakota Gas Tax Rate, http://www.nd.gov/tax/oilgas/pubs/gas-rate.html (reporting that the gas tax rate between 7/2013 and 6/2014 is $0.0833 per thousand cubic feet).

[112] North Dakota Industrial Commission, Department of Mineral Resources, Division of Oil and Gas, Director's Cut (June 17, 2014) https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2014-06-17.pdf (reporting that the value of natural gas delivered to Northern Border at Watford City was $4.23 in April 2014).

[113] 43 CFR § 3103.3-1.

[114] This was the average price of gas from January through December 2013. The monthly delivered to Northern Border at Watford City is reported in the North Dakota Industrial Commission director's cut reports, found at: https://www.dmr.nd.gov/oilgas/directorscut/directorscutarchive.asp

[115] See Orders 20117, 20118 (both related to Baytex Energy wells), and 19159, 19160, 19161, 19162, 19163, 19164 and 19706 (all related to Hess Corp. wells). (Orders can be found on the NDIC web site: https://www.dmr.nd.gov/oilgas/feeservices/ordersearch.asp. NOTE: You must have a paid Premium Subscription to access these files)

[116] Criminal penalties may also be levied if a person willfully violates a rule that pertains to the prevention or control of pollution or waste "unless the penalty for the violation is otherwise specifically provided for and made exclusive in this chapter," indicating that even for such willful violations, the only penalty is payment of taxes and royalties that companies should have been paying anyway.

[117] For example, Hess received 26 exemptions in 2009 alone.

[118] Tex. Nat. Res. Code Ann. §§ 85.045, 85.046.

[119] 16 Tex. Admin. Code Rule § 3.32 (f) (1) (A).

[120] RRC web site" Why does RRC allow flaring?" http://www.rrc.state.tx.us/about-us/resource-center/faqs/oil-gas-faqs/faq-flaring-regulation/. 16 Tex. Admin. Code Rule §§ 3.32 (h) (2), 3.32 (h) (3).

[121] 16 Tex. Admin. Code Rule §§ 3.32 (h).

[122] Railroad Commission of Texas, Flaring Regulation, How Many Flaring Permits Have Been Issued in Texas? http://www.rrc.state.tx.us/about-us/resource-center/faqs/oil-gas-faqs/faq-flaring-regulation/.

[123] Railroad Commission of Texas, Flaring Regulation, Why does RRC allow flaring? http://www.rrc.state.tx.us/about-us/resource-center/faqs/oil-gas-faqs/faq-flaring-regulation/.

[124] Texas Administrative Code. Title 15, Part 1, Chapter 3, Rule 3.32. Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes. (h) Exceptions.

[125] Data are from: 1) Oil and Gas Proposals for Decisions and Orders (results for Rule 32) http://www.rrc.state.tx.us/meetings/ogpfd/index.phpOand and 2) OGC Unprotested Actions – Master Orders http://www.rrc.state.tx.us/meetings/unprotested/new/2008/index.php. Some of the approvals found in the OGC Unprotested Actions –Master Orders were missing from the Oil and Gas Proposals for Decisions and Orders. It is possible that the information had not yet been posted on the Railroad Commission web site. As of May 31, 2014, the missing docket files included: 01-0285583; 01-0287195; 08-0286594.

[126] Railroad Commission of Texas, Online System, Oil & Gas Data Query, http://webapps2.rrc.state.tx.us/EWA/severanceQueryAction.do Data accessed August 21, 2014.

[127] Railroad Commission of Texas web site: "Enforcement Activities: Report on Oil and Gas Field Operations' Violations and Enforcement." http://www.rrc.state.tx.us/oil-gas/compliance-enforcement/enforcement-activities/

[128] According to the Railroad Commission, "the Oil & Gas Division has the authority to cancel an operator's Certificate of Compliance and order that production be shut in at the lease or well level for noncompliance with Commission rules, effectively blocking that operator's ability to sell oil and gas from a lease. Before the operator can resume production, it must correct the violation and pay a statutory fee for restoration of the Certificate of Compliance." http://www.rrc.state.tx.us/oil-gas/compliance-enforcement/enforcement-activities/severanceseal-orders/.

[129] In a phone conversation on June 13, 2014, a representative of the Texas Comptroller of Public Affairs said that flared gas was not taxed though he could not explain why. Earthworks sent an email requesting explanation to tax.policy@cpa.state.tx.us but has not received a response. The reason flared gas is not taxed appears to be that it is not saved, and has no market value under Tex. Tax § 201.052 (providing that gas is taxed at a rate of "7.5 percent of the market value of gas produced and saved in this state by the producer."). Tex. Tax. 201.101 defines market value as "determined by ascertaining the producer's actual marketing costs and subtracting those costs from the producer's gross cash receipts from the sale of the gas." Because flared gas is not marketed or sold, it apparently has no market value.

[130] U.S. Securities and Exchange Commission, Chesapeake Energy Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/895126/000089512614000104/chk-20131231_10xk.htm, at 35.

[131] Murphy Oil Corp., Form 10-K filed with U.S. Securities and Exchange Commission for fiscal year ended Dec. 31, 2013, http://ir.murphyoilcorp.com/phoenix.zhtml?c=61237&p=irol-reportsAnnual, at 24, 29.

[132] U.S. Securities and Exchange Commission, EP Energy Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/1584952/000110465914014368/a14-6541_110k.htm, at 47.

[133] U.S. Securities and Exchange Commission, Comstock Resources, Inc., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/23194/000156459014000379/crk-10k_20131231.htm, at 44. Upstream relates to production of oil and gas rather than the processing or downstream operations. See Schlumberger, Oilfield Glossary, Upstream, http://www.glossary.oilfield.slb.com/en/Terms/u/upstream.aspx.

[134] U.S. Securities and Exchange Commission, EOG Resources, Inc., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/821189/000082118914000007/eogform10-k.htm, at 34.

[135] U.S. Securities and Exchange Commission, Carrizo Oil & Gas, Inc., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/1040593/000104059314000022/crzo201310-k.htm, at F-5.

[136] U.S. Securities and Exchange Commission, Goodrich Petroleum Co., Form 10-K filed for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/943861/000119312514062843/d645377d10k.htm.

[137] U.S. Securities and Exchange Commission, Matador Resources Co., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/1520006/000152000614000017/mtdr10-k12312013.htm, at 51.

[138] U.S. Securities and Exchange Commission, Talisman Energy Inc., Form 40-F for fiscal year ended Dec. 31, 2013, http://investor.shareholder.com/tlm/secfiling.cfm?filingID=1047469-14-1665, at 2-3.

[139] U.S. Securities and Exchange Commission, Marathon Oil Corp., Form 10-K for fiscal year ended Dec. 31, 2013, http://www.sec.gov/Archives/edgar/data/101778/000010177814000014/mro-20131231x10k.htm, at 34.

[140] Jurisdiction and Code Section(s) Prohibiting Waste of Oil, Natural Gas: Bureau of Land Management 30 U.S.C. § 225, 43 CFR § 3161.2; California 1939 Cal. Stat. 3106, 1974 Cal. Stat. 3275, 3276; Colorado O&G Conservation Act, § 34-60-103 (11), 34-60-107; North Dakota N.D. Cent. Code § 38-08-01; Texas Tex. Nat. Res. Code Ann. § 85.045, Tex. Nat. Res. Code Ann. § 85.046

Wyoming Wyo. Stat. Ann. § 30-5-102 (a)

[141] U.S. Environmental Protection Agency, Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document (2010). http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf.

[142] Mike Lee, N.D. Likely to Use Penalties to Cut Gas Flaring, Regulator Says, EnergyWire (July 15, 2014), http://www.eenews.net/energywire/stories/1060002838/search?keyword=north+dakota+flaring (subscription only).

[143] N.D. Cent. Code § 38-08-06.4.

[144] N.D. Cent. Code § 38-08-06.4 (2) (b).

[145] N.D. Cent. Code § 38-08-06.4 (2) (c).

[146] N.D. Cent. Code § 38-08-06.4 (2) (d).

[147] N.D. Cent. Code § 38-08-06.4 (2) (e).

[148] North Dakota Office of State Tax Commissioner, North Dakota Gas Tax Rate, http://www.nd.gov/tax/oilgas/pubs/gas-rate.html (reporting that the gas tax rate between 6/2014 and 7/2015 is $0.0982 per thousand cubic feet). The most recent value of natural gas in North Dakota is $4.23 per thousand cubic feet. North Dakota Industrial Commission, Oil and Gas Division, Director's Cut (June 17, 2013), https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2014-06-17.pdf, at 2.

[149] In a phone conversation on June 13, 2014, a representative of the Texas Comptroller of Public Affairs said that flared gas was not taxed though he could not explain why. Earthworks sent an email requesting explanation to tax.policy@cpa.state.tx.us but has not received a response. The reason flared gas is not taxed appears to be that it is not saved, and has no market value under Tex. Tax § 201.052 (providing that gas is taxed at a rate of "7.5 percent of the market value of gas produced and saved in this state by the producer."). Tex. Tax. 201.101 defines market value as "determined by ascertaining the producer's actual marketing costs and subtracting those costs from the producer's gross cash receipts from the sale of the gas." Because flared gas is not marketed or sold, it apparently has no market value.

[150] Tex. Nat. Res. § 85.381.