Costs of Inefficient Regulation: Evidence from the Bakken

Gabriel E. Lade and Ivan Rudik*

July 13, 2018

Abstract

Efficient pollution regulation equalizes marginal abatement costs across sources. Here we study a new flaring regulation in North Dakota's oil and gas industry and document its efficiency. Exploiting detailed well-level data, we find that the regulation reduced flaring 4 to 7 percentage points and accounts for up to half of the observed flaring reductions since 2015. We construct firm-specific marginal flaring abatement cost curves and find that the observed flaring reductions could have been achieved at 46% lower cost by imposing a tax on flared gas equal to approximately half of current natural gas spot prices instead of using firm-specific flaring requirements.

JEL Codes: L71, Q3, Q4

Keywords: North Dakota, Bakken, hydraulic fracturing, flaring, efficient regulation, oil and gas

*Lade: Iowa State University and the Center for Agricultural and Rural Development. Email: gelade@iastate.edu. Rudik: Cornell University. Email: irudik@cornell.edu. We gratefully acknowledge financial support for this research from the National Science Foundation, Department of Energy, and NBER under the Economics of Energy Markets Grant program, grant number 36269.00.03.00. We thank Dave Keiser, Brian Prest, John Rupp, Carly Urban, Ashley Vissing, and seminar participants at ASSA 2018, Cornell University, East Carolina University, Indiana University, Montana State University, Resources for the Future, University of Minnesota, and the NBER Economics of Energy Markets meetings for helpful comments. Erix Ruiz-Mondaca and T.J. Rakitan provided excellent research assistance.

1 Introduction

A necessary condition for cost-effective regulation is that marginal compliance costs are equal across all regulated sources. Environmental regulations that achieve this condition include pollution taxes and cap-and-trade programs. Despite the increasing prevalence of market-based environmental policies, many environmental regulations still deviate from this central economic principle. Inefficiencies can arise for two reasons. First, policies may inefficiently allocate pollution abatement across sectors or firms. Second, policies may limit intertemporal arbitrage of abatement opportunities, requiring firms to meet the same standard in every compliance period.

The gains from moving to more efficient regulation are usually unknown. Estimating efficiency gains requires knowledge of firms' marginal abatement cost (MAC) curves, which are difficult to recover. Those studies that do estimate MAC curves find that gains from trade can be substantial. Carlson et al. (2000) study the SO_2 emissions trading program under Title IV of the Clean Air Act Amendments of 1990 and find that annual compliance costs were \$800 million (43%) lower with trading compared to a uniform standard. Fowlie et al. (2012) document substantial differences in NO_x abatement costs across the electricity and transportation sectors and estimate that equating MACs across the two sectors could reduce total compliance costs by \$1.6 billion (6%).

In this paper, we study the impacts and efficiency of a new natural gas flaring regulation in North Dakota. North Dakota's Bakken shale formation is valued primarily for its vast unconventional oil deposits. However, when firms extract oil, their wells also produce valuable natural gas and natural gas liquid (NGL) co-products. In the absence of pipeline infrastructure, these co-products are flared: burned at the well site (Swanson, 2014). Flaring has become an acute problem in unconventional oil fields in the US because of the explosion in production over the past decade. Despite the rapid growth in oil production, infrastructure to capture and process associated natural gas has lagged behind. In July 2014, the North Dakota Industrial Commission (NDIC) passed Commission Order 24665 to reduce gas flaring in the state. The regulation established some of the most aggressive flaring standards in the US, and other regulatory agencies have closely followed its progress (Storrow, 2015).

Order 24665 mandates that every operator in North Dakota captures a minimum percentage of gas produced by all their wells, with an ultimate objective of capturing 91% of produced gas in the state by 2020. Several features of the regulation indicate it is inefficient. First, it is firm-specific. Since 2015, every firm operating in North Dakota must meet the same flaring standard. If operators have different marginal costs of capturing gas, the policy inefficiently allocates abatement across firms. Second, firms must meet the same flaring standard every month. If abatement costs change over time due to expanding pipeline infrastructure or firms drilling new wells, firms may inefficiently allocate abatement intertemporally. Gas capture regulations have been identified as among the most difficult and costly regulations for oil-producing firms to comply with (Zirogiannis et al., 2016), suggesting the costs of abatement misallocation may be large.

We begin by characterizing the impact of the NDIC regulation on firms' well operations. We find that on average the regulation decreased flaring rates at new wells by 4 to 7 percentage points in the first year of production and that the regulation accounted for between one-third and one-half of the observed year-on-year reduction in flaring rates at new wells in the state. Firms complied with the regulation by accelerating how quickly they connect their wells to gas capture infrastructure, and by taking longer to complete (i.e., begin producing from) new wells after drilling. Consistent with previous literature, we do not find that firms responded to the regulation by curtailing oil or gas production (Kellogg, 2011; Anderson et al., 2016).

We next construct firm-specific MAC curves. The exercise is motivated by our empirical finding that firms' comply with the regulation by connecting wells to pipeline infrastructure. We use detailed pipeline location data to measure the distance between wells and the nearest pipeline infrastructure. We then use engineering cost estimates to construct on-site and pipeline infrastructure costs for each well, and aggregate the costs to construct firm and industry MAC curves. We use the estimated cost curves to simulate three counterfactual scenarios that achieve the same aggregate flaring reductions that we observe from January 2015 to June 2016, the first eighteen months of the policy.

We document significant heterogeneity in abatement costs, both across firms and over time. Using our preferred cost estimates, reallocating abatement reduces aggregate compliance costs by 46% over the first eighteen months of the regulation. Most of the efficiency gains come from equating marginal abatement costs across firms. We also calculate counterfactual taxes that could achieve the same observed flaring reductions. We find that the state could achieve the same flaring reductions by taxing flared gases at a rate of \$1.35/mcf. To put the value in perspective, the average public lands royalty rate on gas revenues over this period was around \$0.45/mcf. Alternatively, this amounts to taxing carbon emissions from flared gas at \$26/tCO_2, about two-thirds of current social cost of carbon estimates.

Regulators have several incentives to limit flaring. First, flaring is associated with a number of environmental externalities. Worldwide, flaring results in 300 million tons of CO_2 emissions each year, equivalent to the emissions of 50 million cars (World Bank, 2015). Flaring also emits local pollutants including NO_x, SO_2, and aromatic hydrocarbons that have been linked to cardiovascular disease and increased prevalence of cancer. Second, flaring results in economic losses to lease-owners and the government since flared gases are rarely subject to royalty payments and taxes. In the US, federal and state agencies have passed or considered a number of regulations to reduce gas flaring. For example, the Bureau of Land Management and the EPA recently considered rules to regulate flaring and methane emissions (Bureau of Land Management, 2016), while the Fish and Wildlife Service has considered regulating hydraulically fractured wells drilled on and near protected habitats. Globally, the World Bank has a Zero Routine Flaring initiative seeking to eliminate routine flaring by 2030.

Our work contributes to a growing literature studying the economic impacts of the fracking revolution. Previous work has documented the health and pollution impacts of fracking (Olmstead et al., 2013; Hill, 2015); how nearby drilling is capitalized into housing values (Gopalakrishnan and Klaiber, 2014; Muehlenbachs et al., 2015; Bartik et al., 2017); the efficiency of landowner-firm leases (Vissing, 2016); the supply elasticity of fracked versus conventional wells (Newell et al., 2016); and the economic and welfare impacts of these newly reachable resources (Hausman and Kellogg, 2015; Feyrer et al., 2017). Only recently have others begun to analyze firm decision-making in this setting (Covert, 2015; Lange and Redlinger, 2018). To date, little work has studied the effects of environmental regulations on oil and gas firms' decision-making. One contribution of our paper is to take advantage of a rich dataset to develop novel identification strategies to study the impact of policies on well operations.

This paper contributes more generally to an extensive literature studying efficient regulation. Environmental economists have long advocated for moving from command-and-control to market-based policies. The theoretical efficiency of market-based instruments is well established (Montgomery, 1972; Baumol and Oates, 1988) but little work has been able to empirically validate these results (Carlson et al., 2000; Kerr and Newell, 2003; Fowlie et al., 2012).

The paper proceeds as follows. In Section 2, we describe oil production in the Bakken, the institutional and regulatory setting in the state, and the North Dakota flaring regulation. In Section 3, we develop a model of a firm's production and gas connection decisions to clarify the margins through which firms may respond to the regulation and motivate our subsequent simulations. In Section 4 we describe our data and provide summary statistics, and in Section 5 we discuss our empirical strategy and present our results of the effects of the regulation on firms' flaring and production decisions. In Section 6 we estimate firm-specific marginal abatement cost curves and construct counterfactual flaring scenarios. Section 7 concludes. The appendix contains more details on how we perform the counterfactuals, as well as a set of sensitivity and robustness checks.

2 Background

2.1 The Bakken Shale Formation

Much of North Dakota's geology is characterized by "tight" formations where oil is locked into the structure of shale rock. Two advances have drastically improved the economic viability of extracting oil in the region. First, drilling operations have become more efficient at drilling horizontal wells. Since shale formations are found in horizontal layers in the earth, drilling horizontally exposes the well to more oil-rich rock than vertically drilled wells. Second, firms have become more efficient at fracturing shale rock. Fracturing involves injecting fluids into wells at extremely high pressures to fracture the surrounding rock so that oil can flow out of the well.

These innovations transformed the oil and gas industry. In 2015, oil production from fracked wells accounted for nearly half of US production (Energy Information Administration, 2015), and oil production in North Dakota increased tenfold from 90,000 barrels per day (bpd) in 2005 to over 1.2 million bpd in 2015 (North Dakota Industrial Commission, 2016). Firms have also dramatically reduced costs of extraction – break-even oil prices in North Dakota have been recently estimated to be as low as \$35 per barrel (bbl) (Bailey, 2015). North Dakota is likely to continue producing substantial quantities of oil into the future. The US Geological Survey estimates that the Bakken and Three Forks shale formations contain 7.4 billion bbls of oil, nearly 20% of proven recoverable reserves in the United States (Gaswirth et al., 2013; Energy Information Administration, 2016a).[1]

In addition to oil, the Bakken formation contains 6.7 trillion cubic feet of associated natural gas and 530 million barrels of NGLs (Gaswirth et al., 2013). When oil is produced by a fracked well, these gas co-products come along with it. Historically, much of this gas has been flared. This comes at a significant cost to landowners and the state government because flared gas is rarely subject to royalty and tax payments. The lost value of the gas is non-negligible. Flared gas constituted about 14% of the energy content of the produced crude oil from 2006 to 2013 (Brandt et al., 2016), and the commercial value of NGLs flared by North Dakota well operators in May 2013 alone was estimated to be \$3.6 million (Salmon and Logan, 2013).[2]

[1]Three Forks is a smaller formation adjacent to the Bakken. We address both of them as the Bakken.

[2]Flaring is much preferred to venting, or releasing gases directly into the atmosphere. Vented gases contain compounds like hydrogen sulfide that are hazardous to human health. Flaring converts methane and other pollutants to CO_2 and reduces the quantity of other harmful by-products. Venting is also prohibited in North Dakota.

2.2 The North Dakota Flaring Regulation and Firm Compliance

The NDIC passed Order 24665 in 2014 to reduce flaring in the state (North Dakota Industrial Commission, 2015).[3] Before its passage, the only existing flaring regulation was a requirement that operators pay taxes and royalties on flared gas after the first year of production, though discussions with industry participants suggests exemptions were frequently granted (Energy Information Administration, 2016b). Order 24665 created ambitious gas capture goals. The regulation requires that every firm operating in the Bakken capture 77% of their produced gas from January 2015 to March 2016; 80% from April 2016 through October 2018; 85% from November 2016 through October 2018; 88% from November 2018 through October 2020; and 91% after November 2020.

The gas capture requirements are applied uniformly across firms and firms must comply with the regulation every month.[4] Thus, the policy is akin to a within-firm cap-and-trade program, where firms can efficiently allocate abatement among all the wells they own, but cannot trade flaring rights with other firms. The regulation allows firms to bank excess gas captured for up to three months, but does it not allow for borrowing, and the NDIC indicated that few firms have taken advantage of these provisions. Firms that violate the regulation can be ordered to curtail production at out-of-compliance wells to as low as 100 bpd.[5] If a firm is out of compliance for more than three months, it may incur civil penalties of up to $12,500 per day for each well that is below the firm-level capture target.

Firms must comply with the NDIC regulation every month. Each month, the NDIC calculates each firm's capture rate as[6]

$$(\%\ \text{Capture})_i = \frac{\sum_j \left(\mathrm{g}^s_{i,j} + \mathrm{g}^u_{i,j} + \mathrm{g}^p_{i,j}\right)}{\sum_j \mathrm{g}^i_j} \tag{1}$$

where j indexes the wells owned by firm i; $\mathrm{g}^s_{i,j}$ is gas sales from well j; $\mathrm{g}^u_{i,j}$ is gas used on site; $\mathrm{g}^p_{i,j}$ is the gas processed in an approved manner; and g^i_j is total gas produced by well j.[7] Firms' primary compliance mechanism is to connect wells to existing gas pipeline

[3]A task force was first organized to develop a plan to reduce flaring in North Dakota in September 2013. In March 2014 the task force released its report and the ruling was subsequently adopted.

[4]The NDIC was cognizant of cost-effectiveness. Order 24665 explicitly states that it is firm-specific instead of well-specific to give firms "maximum flexibility" in complying with the policy (North Dakota Industrial Commission, 2015).

[5]Average production at new wells from 2015 to 2016 was 633 bpd in the first three months of production and 378 bpd in the first year of production. A substantial portion of industry stakeholders commented during the regulation's hearing on how the curtailments would negatively affect well economics, firm cash flow, and profitability.

[6]Firm compliance is determined with some delay due to reporting lags from industry. For example, the NDIC did not discuss aggregate flaring rates for January 2015 until its March 2015 monthly webinar.

[7]Gas may be used on site to power an electric generator or processed using a natural gas stripping unit.

infrastructure. This involves installing smaller pipelines, called gathering lines, that connect the well site to larger product pipelines that transport the captured gas to processing plants.

Connecting a well to gas capture infrastructure does not eliminate flaring. Flaring at connected wells may still occur due to insufficient capacity of downstream gathering pipelines, product pipelines, or gas processing facilities. Firms have some margins to reduce flaring by changing practices on the well site. For example, a firm can temporarily curtail oil and gas production or use gas for other purposes on site. Alternatively, firms can build "looping" lines to circulate and store gas in case of insufficient downstream capacity.

The NDIC began enforcing the regulation in January 2015, and all active wells in the state were included in firms' gas capture calculations at that time. However, a well is not subject to the regulation for the well's first 90 production days. As a result, firms have substantial flexibility with regards to their flaring rates at new wells until the fourth month of production.

2.3 Oil Production in the Bakken

Understanding the impacts of Order 24665 on firm behavior requires knowledge of firms' decision-making and oil and gas production functions. After firms determine a suitable location and obtain the mineral rights, firms drill or "spud" a well. Most producers hire independent drilling companies for this. Drilling is completed in multiple stages, including: (i) drilling the vertical segment of the well; (ii) drilling one or more "laterals" or horizontal segments through the oil-rich shale layer; and (iii) inserting and securing production casing to protect surface water and ensure the structural integrity of the well. After drilling, firms hydraulically fracture the well. Fracking involves perforating the well casing and injecting large amounts of water, sand, and other additives at high pressure to create and prop open fissures in the surrounding shale rock. A well is "completed" and ready to produce oil and gas after it has been fractured. At this stage, firms install a permanent wellhead and other on-site infrastructure. Oil, gas, and water flow from the wellhead through the flow lines to tanks that separate oil from water and lighter hydrocarbon products. After separation, oil is stored in large containers until it is picked up to be delivered to the nearest pipeline or refinery. If the well is connected to gas gathering infrastructure, the separated gas is transported to nearby gas plants through pipelines. If the well does not have gathering lines installed, separated gas is flared at the well site.

The amount of oil and gas that a well produces is determined by two factors: (i) the amount of hydrocarbons in the underlying shale; and (ii) the length of the well and the intensity with which firms frack the well. Firms can affect the former by drilling in more productive areas. However, firms are not perfectly informed, and they do not always drill into the most productive shale (Covert, 2015). After a well is producing, the amount of oil and gas that comes out of the well is largely determined by the underlying pressure. While operators can curtail production or plug a well, they are unable to make the well more productive unless they re-fracture it.[8]

3 A Model of Gas Capture

We develop a model of an oil and gas producer to better understand the economic incentives underlying the NDIC regulation and identify factors that contribute to the inefficiency of the policy. We model a single firm facing the flaring regulation in a two-stage, static setting. In the first stage, the firm selects the number of wells to drill, J, the location of these wells, the length of the horizontal segment of the well, and how much of each input (e.g., water and sand) to use when fracking the wells. Between the first and second stages, the wells are fracked and completed. At the beginning of the second stage, the oil and gas productivity of each well is realized, and the firm decides whether to connect each well to gas capture infrastructure. At the end of the second stage, oil is sold at price P^o and, if the well is connected to gas capture infrastructure, gas is sold at price P^g. Here we will focus on the second stage.

We make two additional assumptions. First, the firm's connection decision is independent of its oil production (i.e., connecting a well has a negligible effect on oil-related profits). This assumption allows us to abstract from wells' oil production when considering the firm's gas connection decision. Second, we assume that the firm knows the total amount of gas a well will produce when it makes the connection decision. Neither assumption is overly restrictive in our setting. We are unaware of literature documenting oil production losses from installing gas capture infrastructure. After completion, oil and gas production follows a relatively stable decline curve. A common characterization is the 'ARPS' model (Fetkovich, 1980). The model specifies well j's oil and gas production in any period t as

$$\begin{aligned} \mathrm{o}_{jt} &= \mathrm{O}_{j0} t^{\beta_{\mathrm{o}}} \exp(\epsilon_{jt}) \\ \mathrm{g}_{jt} &= \mathrm{G}_{j0} t^{\beta_{\mathrm{g}}} \exp(e_{jt}) \end{aligned} \tag{2}$$

[8]Kellogg (2011) and Anderson et al. (2016) study conventional oil wells in Texas and argue that oil prices impact well drilling rather than production from existing wells. They show that along an equilibrium path, firms always keep wells producing at their maximum possible level regardless of the prevailing oil price. This result has one caveat in unconventional oil setting: firms may re-pressurize unconventional wells by re-fracking.

where o_{jt} and g_{jt} are the well's oil and gas production at time t; O_{j0} and G_{j0} are the initial levels of oil and gas production from the well; β_o and β_g are the oil and gas decline rates; and ϵ_{jt} and e_{jt} are noise terms. In the first stage, the firm's input choices and the underlying geology determine O_{j0} and G_{j0}. So long as ϵ_{jt} and e_{jt} are small and mean zero, firms can estimate the total oil and gas that a well will produce with a fair degree of confidence after observing a well's initial production and decline rates at similar wells.[9]

Consider the firm's second stage problem. Wells are heterogeneous in the amount of gas they produce and their connection costs. Well j produces g_j units of gas over its lifetime, which can be calculated by summing equation (2) over the lifetime of the well. We denote the connection costs for well j as $C_j(h_j)$, where $h_j \in \{0, 1\}$ and 1 indicates that the well is connected to a gathering line while 0 indicates that it is left unconnected. We assume that $C_j(0) = 0,\ \ C_j(1) > 0$.[10] We model the NDIC flaring restriction as a minimum fraction of gas that must be captured by the firm across all its wells, $\bar{F} \in (\alpha, 1]$ where $\alpha > 0$ is sufficiently high so that the flaring constraint binds.

The firm's problem is

$$\max_{h_1,\ldots,h_J} \sum_{j=1}^{J} P^g\, g_j\, h_j - C_j(h_j)$$

$$\text{subject to:} \quad \frac{\sum_{j=1}^{J} g_j\, h_j}{\sum_{j=1}^{J} g_j} \geq \bar{F} \quad \text{and} \quad h_j \in \{0,1\}\ \ \forall j = 1, ..., J$$

Let λ denote the Lagrange multiplier on the flaring constraint. The firm connects well j if

$$P^g + \lambda \geq \frac{C_j(1)}{g_j}, \qquad j = 1, ..., J. \tag{3}$$

The firm connects well j if the marginal benefit of selling gas, the market price plus the firm's shadow price of the constraint, is greater than the cost of connecting the well per unit of gas produced over its lifetime.

The first-order condition yields key insights that allow us to empirically evaluate the efficiency of the regulation. A cost-effective policy equalizes shadow prices across all firms, and in a dynamic model, a cost-effective policy equalizes a firm's shadow price over all compliance periods. If $\bar{F}$ is applied uniformly across different firms, then λ will differ across firms if they own portfolios of wells with heterogeneous connection costs or gas productivity.

[9] While unconventional drilling remains a relatively new technique, there is evidence that unconventional wells have less variability in realized production than conventional wells (Newell et al., 2016).

[10] Gathering line costs vary along two important dimensions: (i) distance to the nearest product pipeline; and (ii) the diameter of the line (ICF International, 2018).

Letting m denote the marginal well that a firm connects to gas capture infrastructure, differences in $C_m(1)/g_m$ across firms indicates differences in λ across firms and that the flaring regulation inefficiently allocates gas capture. Alternatively we can think of different firms in this static model as the same firm but at different points in time, assuming the firm is not forward-looking. A cost-effective policy would require that the per unit connection cost of the marginal well be equal in all compliance periods. We take advantage of these insights in Section 6.1 when we construct firm marginal abatement costs curves.

4 Data Description and Summary Graphs

Our data consist of monthly, well-level production, flaring, and sales data reported by the NDIC for over 9,300 horizontal wells owned and operated by 54 firms in North Dakota between 2007 and 2016. For most of our analysis, we focus on the roughly 6,800 wells completed between January 2012 and June 2016. We process the data from the NDIC in a few ways. First, we focus on oil and gas wells in the Bakken or Three Forks shale formation since the NDIC regulation applies only to these wells. Second, we drop wells where we observe the maximum level of oil production occurring more than five months after we observe their first production. These wells have likely been re-fracked and are not comparable to other wells.[11]

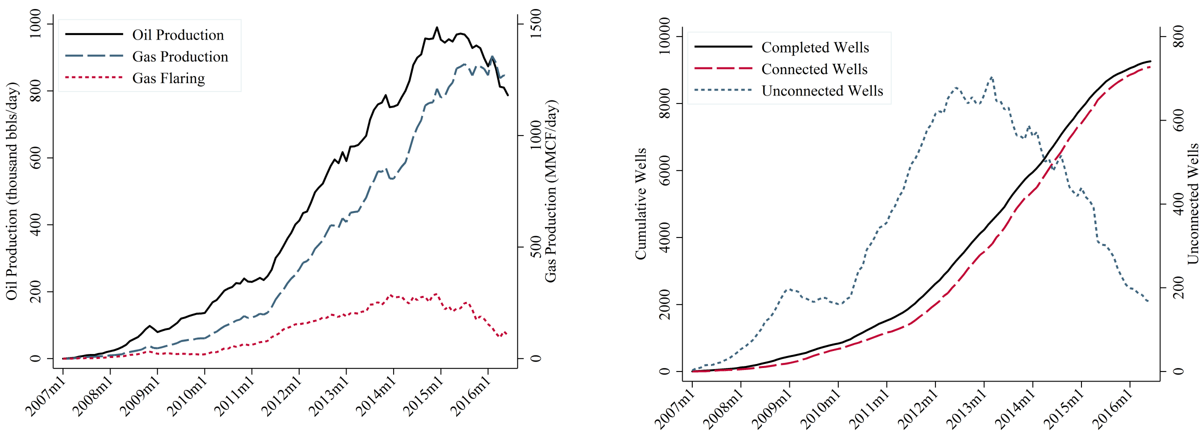
We observe a number of well-level characteristics including the year and month of spudding and completion; wells' latitude/longitude; well depth and horizontal length; and the current and original owner of all wells.[12] We merge the data with well characteristics from a number of other sources. First, we obtained GIS data for all natural gas and oil pipelines in 2016 from Rextag. We use the data to calculate the distance between every well and the nearest gas gathering or transmission pipeline.[13] Second, we merge data on the volume of the wells' fracking inputs from the FracFocus Chemical Disclosure Registry. We obtain weather data from the nearest weather monitoring station provided by the North Dakota Agricultural Weather Network, and snowfall data from the NOAA National Operational Hydrologic Remote Sensing Center. Last, we control for historical oil and gas price data using futures

[11] We drop just over 1,000 wells as a result of these restrictions.

[12] Only the most recent operator and initial operator are provided. We do not observe sales date and therefore cannot determine when well purchases occurred.

[13] A disadvantage of the Rextag data is that we only observe a cross-section of North Dakota's pipeline network. We do not observe when each pipeline became active. We have also explored distance to the nearest well connected to gas capture infrastructure as an alternative distance measure that is time-variant to proxy for the roll-out of the gas pipeline network. Using this alternative measure does not affect our primary results.

Figure 1: Oil and gas production, gas flaring, and well completions in the Bakken.



(a) Aggregate Oil & Gas Production and Flaring

(b) Completed and Connected Wells

Notes: Figure 1a graphs total production and flaring from all horizontal wells in our sample from January 2007 to June 2016. Figure 1b graphs the cumulative number of completed and connected wells (left axis), and the number of unconnected wells (right axis) over the same period.

prices for Henry Hub (HH) natural gas and Clearbrook oil prices from Bloomberg.[14,15]

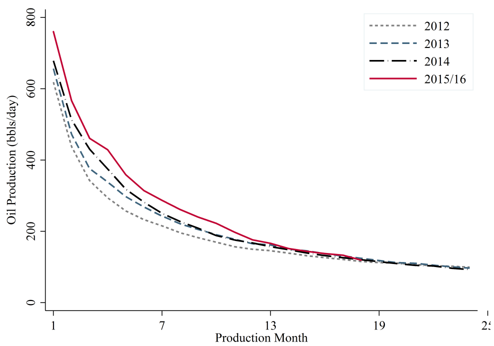
Figures 1a and 1b graph monthly oil and gas production, gas flaring, the number of completed and connected wells, and the number of unconnected wells from January 2007 to June 2016 for all wells in our sample. Oil and gas production grew exponentially until mid-2014 when oil prices began to fall. Operators flared a substantial amount of their produced gas over this period. Flaring rates regularly exceed 30% through early 2014. Both the amount and rate of flaring has decreased since the beginning of 2015 when the flaring regulation began. Figure 1b highlights one of the main mechanisms through which firms have reduced flaring – the number of unconnected wells in the state has declined rapidly, with a large drop around January 2015.

Figure 2 graphs average oil production, gas production, flaring rates, and the fraction of wells connected to gas capture infrastructure in well 'production time.' Production time is defined as the months since the first month of observed oil production from a well. The

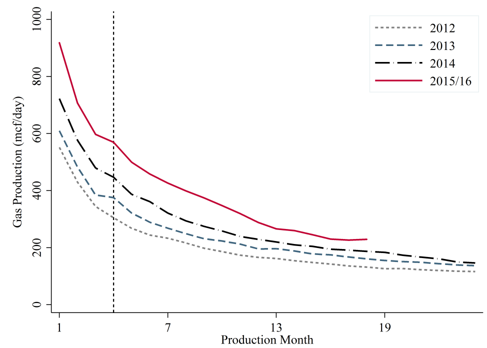
[14] Results are similar if we use West Texas Intermediate (WTI) crude oil prices or Guernsey crude oil prices. We are unaware of any posted prices for natural gas or NGL co-products in the state. However, recent work by Avalos et al. (2016) suggests that natural gas prices are integrated even in distant markets across the US.

[15] Clearbrook prices are spot prices. We also explored using different WTI futures price specifications. Results are not sensitive to using the average of all concurrently traded WTI contract prices for up to twelve months ahead, the 6 month ahead futures price, or the 12 month ahead futures price. In are main specification, Henry Hub prices are the average of all concurrently traded contract prices for up to twelve months ahead.

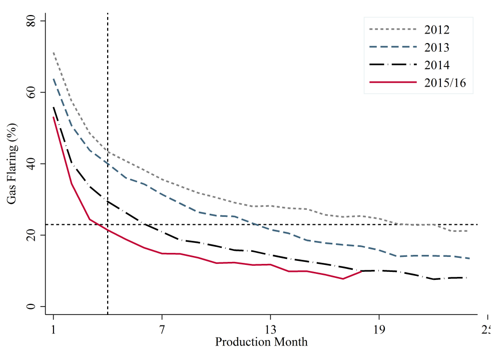
Figure 2: Well production, flaring and connection rates by production month.



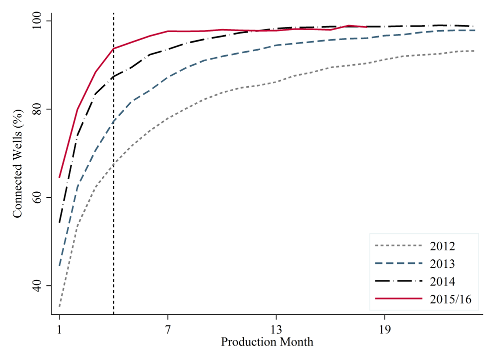
(a) Average Oil Production



(b) Average Gas Production



(c) Average Flaring Rate



(d) Average Connection Rate

Notes: The figures graph average oil and gas production, flaring rates, and connection rates in production time at wells completed in 2012, 2013, 2014, and 2015/16. The dotted lines in subfigure (c) indicate the January 2015 flaring target and the fourth month in production time.

figures document the substantial productivity gains over time. Initial oil and gas production averaged 600 bpd and 600 thousand cubic feet per day (mcf/day) in 2012. By 2015–2016, initial oil production increased by 25% to 750 bpd and gas production increased by 50% to nearly 900 mcf/day. The figures also illustrate the approximately exponential decline rate in oil and gas production over the first year of production.

Flaring rates decline slowly over wells' productive lifetimes. In 2012 and 2013, firms flared around 40% of the gas that wells produced in their fourth production month, and flaring rates remained above 20% even after a full year of production. Wells completed in 2014 and 2015-2016 display nearly identical flaring rates in the first two production months. However, beginning in month three, wells completed in 2015–2016 show a rapid decline in flaring relative to 2014 until around the eighth production month. In the fourth month, when wells are subject to the flaring regulation, average flaring at wells completed in 2015–2016 is about 23% – the flaring limit set by the NDIC for 2015. Figure 2d graphs the fraction of wells that connected in a given production month. In 2012 and 2013, just around 40% of wells connected to gas infrastructure in their first production month, but by 2014–2016 this increased to about 60%.[16]

5 Effects of the NDIC Flaring Order

In this section, we describe our empirical strategy to estimate the impact of the NDIC regulation on flaring rates at new wells in North Dakota. We then describe our methods to disentangle the mechanisms by which firms respond to the regulation. We focus on: (i) time to complete wells; (ii) time to connect wells to gas capture infrastructure; and (iii) oil and gas production.[17] Last, we present our results.

5.1 Empirical Strategy: Flaring

We begin with a reduced form description of the regulation's effects. Our main empirical strategies use difference and difference-in-differences estimation. We limit our analysis to the impact of the regulation on wells completed after January 2015 and focus on wells' first year of production for a few reasons. First, a large amount of a well's lifetime gas production occurs in the first year.[18] Second, a main goal of Order 24665 is to incentive wells to connect to gas capture infrastructure early in their production lifetimes. The NDIC gas capture calculation, equation (1), disproportionately decreases if a new, high-production well is not connected by its fourth production month. Third, the NDIC requires firms to pay taxes and royalties on flared gas after their first year of production. Given our empirical strategy defined below, we do not want to conflate the impacts of the Order with other requirements that firms face after their first production year.

We define our treatment group as North Dakota wells that were completed after 2015. Ideally we would observe wells drilled in similar locations over the same period that happened to be exempt from the regulation. While there is some unconventional oil production in the Bakken formation in nearby Montana, few wells were drilled over our period of interest.[19] We instead take advantage of the fact that wells drilled in North Dakota before the regulation

[16]Table A.1 in Appendix A presents other relevant summary statistics, comparing wells completed in 2012–2014 to those completed after 2015.

[17]We do not consider other margins such as well location, well length, or fracking input choice. Conversations with regulators and operators in North Dakota suggest that drilling and location decisions are primarily determined by oil motives rather than gas.

[18]Based on our estimated ARPs decline rate of -0.342 from wells in our sample, gas production declines by over 57% on average after the first year of production.

[19]We report results when adding in Montana data for difference-in-differences and triple differences specifications in Appendix C. The results support our empirical strategy proposed here.

have very similar production patterns over their lifetimes.

In our main specifications, we define control wells as those that were completed in 2014 and define time in our estimation as production time. Wells completed in 2014 are eventually subject to the regulation. For example, flaring from a well completed in July 2014 is included in the firm's flaring calculations beginning in January 2015. Thus, we drop control well observations from calendar year 2015.[20] We include a number of covariates and fixed effects in our regressions to control for important factors that may differentially affect flaring at wells completed after 2015 versus those completed in 2014.

Our first empirical strategy is a differences strategy that compares flaring rates at wells completed in 2014 versus those completed after 2015 over their first year of production. We estimate the following regression:

$$Y_{ift\tau} = \rho \mathbf{1}[\text{Completed 2015}] + g(t;\Theta) + \mathbf{X}'_{if\tau}\beta + \varepsilon_{ift\tau}, \tag{4}$$

where $Y_{ift\tau}$ is the flaring rate at well i owned by firm f in production month t and calendar month τ.[21] $\mathbf{X}_{if\tau}$ includes the log of the well's gas production; the log of changes in HH and Clearbrook prices; the log distance to nearest pipeline; and local weather conditions.[22] The function $g(t;\theta)$ is a flexible function in production time that controls for common practices across wells in each production month. In our main specification, we specify $g(t;\Theta)$ as production time fixed effects. We also include township fixed effects in $\mathbf{X}_{if\tau}$ to control for fixed characteristics of wells' location, firm fixed effects to control for fixed owner characteristics, and month fixed effects to control for seasonality in production, drilling, and prices.[23]

Our second empirical strategy leverages the fact that wells are not included in firms' aggregate flaring calculations until their fourth production month. For this, we estimate the following difference-in-differences regression:

$$Y_{ift\tau} = \rho \mathbf{1}[\text{Completed 2015}, t \geq 4] + g(t;\Theta) + \mathbf{X}'_{if\tau}\beta + \varepsilon_{ift\tau}. \tag{5}$$

The controls are the same as the prior specification, with the exception that well fixed effects

[20]We perform a suite of sensitivity and robustness checks in the appendix, including using alternative control groups and empirical specifications. We also conduct a number of placebo tests to validate our empirical strategy. Results are generally robust to all specifications, and placebo tests support the validity of our design.

[21]For example, $Y_{if,1,\tau}$ is the percent of the produced gas that is flared at well i in its first month of production, and $Y_{if,12,\tau}$ is the percent of produced gas flared in the twelfth month of production.

[22]We cannot reject the null hypothesis that log Clearbrook and Henry Hub prices contain a unit root over our sample and the two series are highly collinear in levels. We, therefore, first difference the series in all regressions, controlling for whether prices are increasing or decreasing in any given month. Weather controls include total precipitation and temperature.

[23]A township is a 6-by-6 mile square defined by the US Geological Survey.

are included in $\mathbf{X}_{if\tau}$.

Our last empirical strategy is a matching estimator that compares flaring at wells completed in 2015 versus those completed in 2014. We use nearest-neighbor matching for every well completed after 2015 to its five closest matches from wells completed in 2014. We match wells based on their initial gas production, well depth, distance to a pipeline, average log difference in Clearbrook and HH prices, and the number of months that we observe the well.[24] The simplest representation of our estimated treatment effect is given by:

$$\hat{\rho} = \frac{1}{N} \sum_{i=1}^{N} \left[\hat{Y}_i(1) - \hat{Y}_i(0) \right], \tag{6}$$

where $\hat{Y}_i(1)$ and $\hat{Y}_i(0)$ are the appropriately adjusted average flaring rates at wells that are subject to the regulation and not subject to the regulation.

Our identifying assumption is that, absent the NDIC regulation and conditional on our full set of controls, flaring rates for wells completed in 2015 would have the same level over the first year of the production as at wells completed in 2014 for the differences and matching strategies, and that flaring rates for wells completed in 2015 would follow parallel trends to wells completed in 2014. All strategies defined above identify changes in average flaring rates over either the entire first year of well production or the over fourth to twelfth production months.

We also explore heterogeneity in the regulation's effect throughout a well's lifetime by estimating difference-in-differences regressions of the form:

$$Y_{ift\tau} = \sum_{s=2}^{12} \rho_s \mathbf{1}[\text{Treated, t=s}] + g(t;\Theta) + \mathbf{X}'_{if\tau}\beta + \alpha_i + \varepsilon_{ift}. \tag{7}$$

Equation (7) allows for separate coefficients ρ_s for the second through twelfth production months.

5.2 Empirical Strategy: Mechanisms

We use similar empirical strategies to study how firms comply with the regulation. We consider three margins of behavior. First, we test whether firms take longer to complete wells after spudding (drilling). This may indicate that firms install more on-site infrastructure, including gas capture infrastructure. Second, we test whether firms connect to gas capture

[24] We use a Mahalanobis scaling matrix to determine our matched sample. We match wells exactly on the number of production months. Following Abadie and Imbens (2011), we adjust the estimates for bias resulting from matching on more than one continuous covariate.

infrastructure more quickly. Because output is highest in the first production months, reducing time to connection can increase the total amount of gas captured. Last, we test whether firms curtail oil and gas production at wells subject to the regulation.

Spud-to-completion and first production-to-connection duration: We estimate survival (hazard) models for the spud-to-completion time and first production-to-connection time. In the former, wells "survive" if they are not completed (i.e., not producing) t months after spudding, and "die" if they are completed. In the latter, firms "survive" if they remain unconnected to gas capture infrastructure t months after initial production and "die" if they connect. We define control and treatment groups as before, consider only the first twelve production months, and throw out data for wells completed in 2014 after January 2015.

We first estimate a non-parametric Kaplan-Meier (KM) survivor function for each outcome. Let $\bar{t}_j$ denote the production month a well is completed or connected to gas capture infrastructure, i_j denote the number of wells not completed or connected before production month $\bar{t}_j$, and c_j be the number of wells that are completed or connected in production month $\bar{t}_j$. The KM function is given by:

$$\hat{S}(t) = \prod_{j|\bar{t}_j \leq t} \left(\frac{i_j - c_j}{i_j} \right). \tag{8}$$

We estimate equation (8) separately for wells completed in 2014 and those completed after 2015.

Equation (8) does not control for differences in the economic environment, gas capture infrastructure, or weather between the treatment and control groups. We therefore also estimate a parametric survival model with time-varying controls. Specifically, we estimate a hazard function for wells that are either completed or connected in period t as:

$$h(t, 1[\text{Treated}], \mathbf{X}_{it}; \Theta) = \frac{f(t, 1[\text{Treated}], \mathbf{X}_{it}; \Theta)}{1 - F(t, 1[\text{Treated}], \mathbf{X}_{it}; \Theta)}, \tag{9}$$

where $f(\cdot)$ and $F(\cdot)$ are Weibull density and cumulative density functions of the spud-to-completion time or first production-to-connection time.[25] For our spud-to-completion regressions, the covariates $\mathbf{X}_{it}$ include fracking inputs, well depth, oil and gas prices, and distance to nearest pipeline. For time to connection regressions, we control for initial gas production, distance to pipeline, and oil and gas prices. Our coefficient of interest in both

[25] Results are similar using an exponential and Gompertz survival distribution. Newell et al. (2016) use a generalized gamma distribution to estimate spud-to-completion times for conventional and unconventional oil wells in Texas. Results using a generalized gamma model are also similar to our Weibull results when we do not include covariates. However, including controls in the model leads to convergence issues.

cases is on the indicator function for whether the well was completed after 2015.

To facilitate interpretation we also estimate regression-adjusted average treatment effects (ATE) on the spud-to-completion time and first production-to-connection time. We first estimate separate Weibull survival models for wells completed in 2014 and those completed after 2015. To ensure we have one predicted survival time for each well, we estimate a time-invariant version of equation (9). We then predict and compare the average survival times for each group to estimate an ATE of the regulation on time to completion and connection.[26]

Oil and gas production: Last, we test whether the regulation affects wells' oil and gas production. We estimate regression equations (4) and (5), where we replace $Y_{ift\tau}$ with the logarithm of oil or gas production. In these regressions, the function $g(t;\Theta)$ controls for the average oil and gas decline curve. Similar to Newell et al. (2016), we use three forms of $g(\cdot)$: (i) an ARPS model where $g(\cdot)$ is the logarithm of production time; (ii) a cubic spline in production time;[27] and (iii) production time fixed effects. Controls include oil or gas prices, initial oil or gas production, local weather conditions, and township fixed effects. As above, we also use a matching estimator comparing wells' oil and gas production for wells completed in 2014 versus those completed after 2015.

5.3 Results: Flaring Treatment Effects

Table 1 presents our estimates of the effect of the regulation on flaring. Columns (1) to (3) show estimates of the treatment effects over the first year of production, and columns (4) to (6) show estimates of the treatment effects over the fourth to twelfth production months. Panel A includes all wells, and Panel B includes only wells that were connected by their second production month. The latter is meant to test whether the regulation impacts routine flaring after a well is connected to gas gathering infrastructure.

After controlling for observable differences between wells completed in 2014 versus those completed after 2015, we find that wells flared 4.5% to 7.5% less on average over their first production year. The magnitude of the results differ significantly between the difference-in-differences estimates and the matching estimators for months four to twelve, where the difference-in-differences estimate suggests a relatively small effect.

[26]Coefficients for the time-invariant survival function are similar to the time-varying parameter survival model.

[27]We estimate a four-knot restricted cubic spline with knots at 1.1, 1.4, 2, and 2.4 months. Knots are clustered early in the production lifetime since this is where the most curvature is in the production path.

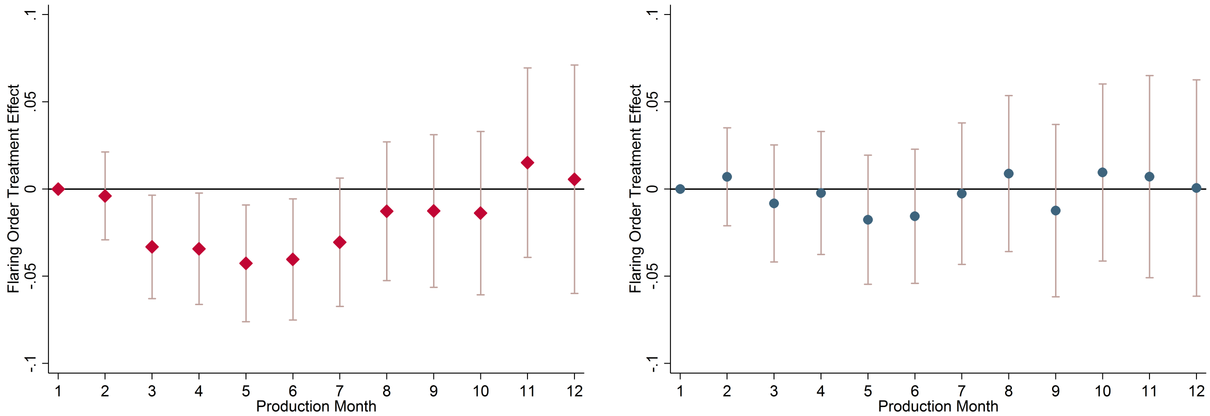
Table 1: Average effect of the regulation on flaring rates.

	(1)	(2)	(3)	(4)	(5)	(6)
	Dif	Dif	NN Match	D-in-D	D-in-D	NN Match
Panel A: All Wells						
Post-2015 (M1-M12)	-0.112***	-0.045***	-0.076***			
	(0.008)	(0.011)	(0.011)			
Post-2015 (M4-M12)				-0.027**	-0.019*	-0.081***
				(0.011)	(0.011)	(0.011)
Log Gas Production		0.034***			0.044***	
		(0.002)			(0.002)	
Log Dist. to Gathering Line		0.027***				
		(0.003)				
Δ Log HH Price		-0.448***			-0.187***	
		(0.063)			(0.056)	
Δ Log Clearbrook Price		-0.193***			-0.080***	
		(0.031)			(0.029)	
Observations	26,610	26,610	3,292	26,423	26,423	2,747
Wells	3,358	3,358	3,292	3,171	3,171	2,747
Panel B: Wells Connected by Second Production Month						
Post-2015 (M1-M12)	-0.034***	0.002	0.018*			
	(0.008)	(0.010)	(0.010)			
Post-2015 (M4-M12)				-0.023**	-0.007	0.018*
				(0.012)	(0.012)	(0.010)
Log Gas Production		0.012***			0.016***	
		(0.003)			(0.003)	
Log Dist. to Gathering Line		0.012***				
		(0.003)				
Δ Log HH Price		-0.237***			-0.128*	
		(0.065)			(0.068)	
Δ Log Clearbrook Price		-0.166***			-0.085**	
		(0.033)			(0.034)	
Observations	15,527	15,527	1,980	15,414	15,414	1,631
Wells	1,980	1,980	1,980	1,867	1,867	1,631
Well FE	No	No	No	Yes	Yes	No
Firm FE	No	Yes	No	No	No	No
Township FE	No	Yes	No	No	No	No
Production Month FE	No	Yes	No	Yes	Yes	No
Calendar Month FE	No	Yes	No	No	Yes	No
Weather Controls	No	Yes	No	No	Yes	No

Notes: The dependent variable is the well-level flaring rate. The coefficients of interest are Post-2015 (M1-M12), which equals one if the well was completed after 2015, and Post-2015 (M4-M12), which equals one if the well was completed after 2015 and it is after the well's fourth production month. Dif, D-in-D, and NN Match denote our differences, difference-in-differences, and nearest neighbor matching estimators. Regression standard errors are clustered at the well level, and NN match standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Panel B presents results for connected wells. We find no systematic reduction in flaring across these wells when we include all of our control variables. The result suggests that the

Figure 3: Treatment effects of the regulation on flaring rates by production month.



(a) All Wells (b) Connected Wells

Notes: Figure 3 graphs the point estimates and 95% confidence intervals from estimating equation (7). Time is specified in production time, and the effects are relative to the regulation's effect in the first production month. Figure 3a includes all wells, and Figure 3b includes wells that were connected in the first two production months. Both regressions include the same controls as in column (5) of Table 1. Standard errors are clustered at the well level.

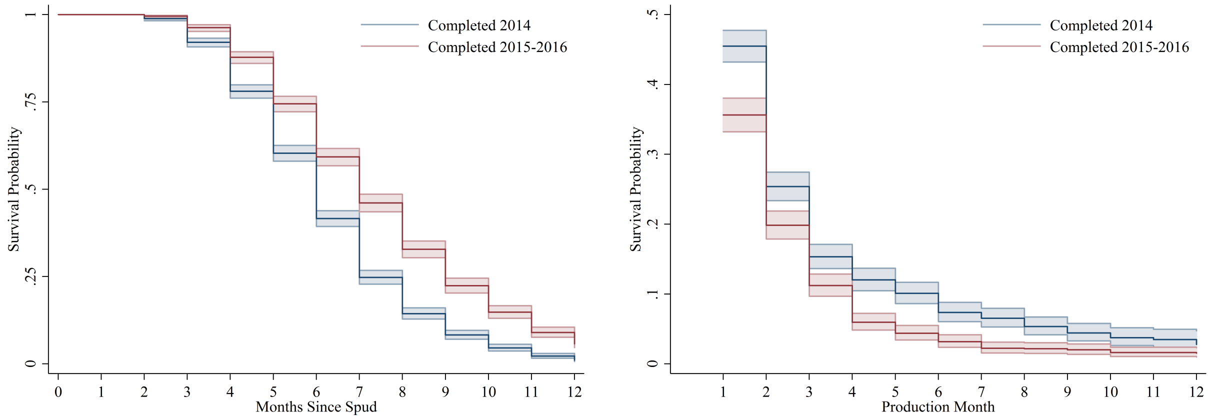
regulation has little to no impact on routine flaring. The point estimates for other covariates have intuitive signs. Firms flare more at wells if they produce more gas and if they are further from pipeline infrastructure, and firms flare less when natural gas prices are improving.

Figure 3 graphs the results from estimating equation (7). The regression includes the same controls as in column (5) of Table 1, and we present estimates for all wells and those that were connected in their first two production months. All estimates are relative to the omitted first production month. When we consider all wells, flaring reductions are concentrated between the third and seventh production months, where we find a 3% to 4% reduction in flaring rates relative to control wells. As before, we find no discernible impact of the regulation on flaring at connected wells.

5.4 Results: Mechanisms

Figure 4 graphs the KM survival functions and corresponding 95% confidence intervals for wells' spud-to-completion and first production-to-connection times. Figure 4a graphs the survival probabilities for each month since initial spudding. In all months, the survival probability (non-completion probability) is higher for wells spudded after 2015 than those spudded in 2014. Six months after spudding, only 42% of 2014 wells remained incomplete, while over 55% of 2015–2016 wells remained incomplete. Figure 4b graphs survival proba-

Figure 4: Kaplan-Meier survival estimates.



(a) Spud-to-Completion Time (b) First Production-to-Connection Time

Notes: Figure 4 graphs KM survival probabilities and 95% confidence intervals for wells completed in 2014 and after 2015. Figure 4a graphs KM survival probabilities for spud-to-completion time. Figure 4b graphs KM survival probabilities for first production-to-connection time.

bilities for the time-to-connection duration models. Wells completed after 2015 have lower survival rates in all months. In the first production month, 45% of wells completed in 2014 remained unconnected while 35% of wells completed in 2015 were unconnected. We observe smaller differences in survival probabilities in the second and third production months. However, in the fourth month when new wells become subject to the regulation, the survival probability for wells completed after 2015 falls sharply, and the survival function remains lower through the ninth production month.

Tables 2 and 3 present estimates from our structural survival models. Coefficients from the survival model in columns (1) to (3) are specified in accelerated failure-time so that a one unit change in explanatory variable x_j increases the failure time by $\exp(\beta_j)$. Columns (4) and (5) present the regression-adjusted mean completion time for 2014 wells and the difference in completion time (measured in months) between wells completed in 2014 and those completed after 2015. Consistent with the KM estimates, wells spudded after 2015 have longer spud-to-completion times and quicker connection times than those completed in 2014. In our specification with the full set of controls, we find that wells completed after 2015 have over 20% longer completion times, taking around 1 month longer to be completed on average. Conditional on producing, wells completed after 2015 have 12% shorter non-connection times, and connect to gas capture infrastructure 0.7 months sooner than wells completed in 2014, on average.

Table 2: Spud-to-completion duration.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Completed Post-2015	0.197***	0.196***	0.206***	1.220***	1.108***
	(0.014)	(0.015)	(0.015)	(0.094)	(0.096)
Log Water Inputs		0.024**	0.024**		
		(0.010)	(0.011)		
Log Non-Water Inputs		-0.004	-0.003		
		(0.004)	(0.004)		
Log Well Depth		0.181**	0.246***		
		(0.089)	(0.089)		
Δ Log HH Price		0.432***	0.511***		
		(0.101)	(0.116)		
Δ Log Clearbrook Price		0.026	0.203***		
		(0.054)	(0.065)		
Log Distance to Pipeline		-0.015**	-0.016***		
		(0.006)	(0.006)		
Mean Completion Time				6.274***	6.288***
(2014 Wells)				(0.056)	(0.060)
Observations	22,844	21,895	21,605	3,185	3,182
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is the spud-to-completion duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

Table 3: First production-to-connection duration.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Completed Post-2015	-0.140***	-0.087***	-0.124***	-0.541***	-0.684***
	(0.040)	(0.032)	(0.032)	(0.077)	(0.084)
Log Gas Production		-0.249***	-0.251***		
		(0.011)	(0.011)		
Δ Log HH Price		-0.688***	-0.050		
		(0.162)	(0.198)		
Log Distance to Pipeline		0.114***	0.114***		
		(0.011)	(0.011)		
Mean Connection Time				2.321***	2.405***
(2014 Wells)				(0.065)	(0.074)
Observations	6,523	6,523	6,503	3,131	3,128
Model	AFT	AFT	AFT	ATE	ATE
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is first production-to-connection duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

Table 4: Oil and gas production.

(4.A) Oil Production

	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Post-2015 (M1-M12)	-0.011	-0.003	-0.002	0.033
	(0.022)	(0.022)	(0.022)	(0.033)
Log Initial Oil Production	0.288***	0.288***	0.288***	
	(0.017)	(0.017)	(0.017)	
Δ Log Clearbrook Price	-0.090	-0.028	-0.034	
	(0.062)	(0.063)	(0.063)	
Observations	26,610	26,610	26,610	3,358
Wells	3,358	3,358	3,358	3,358
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

(4.B) Gas Production

	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Post-2015 (M1-M12)	0.042	0.050*	0.050*	0.027
	(0.026)	(0.027)	(0.027)	(0.036)
Log Initial Gas Production (mcf/day)	0.261***	0.261***	0.261***	
	(0.016)	(0.016)	(0.016)	
Δ Log HH Price	0.117	0.179	0.182	
	(0.124)	(0.126)	(0.126)	
Observations	26,140	26,140	26,140	3,292
Wells	3,292	3,292	3,292	3,292
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

Notes: The coefficients of interest are Post-2015 (M1-M12), which equals one if the well was completed after 2015. Dif and NN Match denote our differences and nearest neighbor matching estimators. Standard errors are clustered at the well level, and standard errors in the NN match specifications are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table 4 presents our results for the effects of the regulation on firms' oil and gas production. We find no consistent differences in oil or gas production across specifications at wells completed after 2015 compared to those completed in 2014. Thus, on average, we find no evidence that firms curtail production in response to the regulation. This is consistent with previous work – conditional on drilling a well it is optimal for firms to produce at maximum capacity (Kellogg, 2011; Anderson et al., 2016).

6 Heterogeneous Costs and Gains from Trade

In this section, we take advantage of the key insights from our theoretical model and empirical results to construct firm MAC curves. We use the estimated MAC curves to study the efficiency of the NDIC regulation, and quantify potential gains from instituting more flexible flaring standards in the state. We explore three counterfactual policies. The first allows for inter-firm trading but continues to enforce the same flaring standard in every month. The second allows for inter-temporal trading but leaves in place the firm-specific standard. The third combines the two forms of trade.

6.1 Firm Abatement Costs

Section 3 showed that a firm connects a well if the cost of doing so is below some threshold. In a static setting with continuous abatement cost functions, the regulation achieves a given aggregate flaring reduction at minimum total cost if and only if marginal abatement costs are equalized across firms.[28] In our setting, firms have discrete connection decisions so equality across firms may not hold. Thus, we require a slight modification to this rule. The regulation is cost-effective if and only if all connected wells were connected at a lower cost per unit of gas captured than wells left unconnected.

Other features of our setting complicate this static efficiency measure. First, we observe empirically that firms ultimately connect most of their wells to gas capture infrastructure. Second, abatement costs evolve – new wells begin producing oil and gas every month, and the potential gas captured at a given well decreases every month that it is not connected. Last, firms must comply with the regulation in every month. Given this, we limit our analysis in a few important ways. First, we restrict our attention to the efficiency of the policy in its first eighteen months. Second, we assume the ex-post observed flaring reductions over this period are the desired levels envisioned by the NDIC. This allows us to calculate total abatement over the first year-and-a-half of the program, construct counterfactual compliance paths for firms that achieve the same aggregate abatement, and compare abatement costs across scenarios.

We first must construct firm and industry MAC curves. For a given month, we construct firm MAC curves by calculating the right-hand side of equation (3) for every well owned

[28] This condition need not hold in a dynamic setting. For example, a firm may connect a well that statically has connection costs that are 'too high' because the firm is forward-looking and anticipates connecting more wells to newly developed infrastructure in the future. We do not study forward-looking behavior here.

by a firm that is not already connected to gas capture infrastructure in that month. The calculation consists of two components: (i) the well connection costs; and (ii) the well's expected gas production. We calculate the latter using the ARPS model from Table 4. We specify well i's gas production g_{it} in any month t as:

$$log(\mathrm{g}_{it}) = \beta_1 \log(t) + \theta_i + \varepsilon_{it} \tag{10}$$

where θ_i is a well fixed effect. The estimated decline rate is $\hat{\beta}_1 = -0.342$. For new wells, we assume firms know G_{i0}, the initial gas production from well i. Given G_{i0} we can compute the expected lifetime gas production g_i for any well i. We use a twenty year lifetime to calculate the total amount of gas that a well will produce.

Given g_i we compute the right-hand side of equation (3), the per unit connection cost for connecting the well, as:

$$\frac{\text{(On-site Fixed Costs)} + \text{(Inch-Mile Line Costs)} \times d_i \times w_i}{g_i}. \tag{11}$$

The first term in the numerator is the fixed cost of on-site equipment.[29] The second term is the cost of constructing a gathering line to well i, which is a function of the length of the line, d_i and also the diameter of the line w_i.

We construct these costs using data from ICF International in a report prepared for the Interstate Natural Gas Association of America (INGAA) (ICF International, 2018). ICF reports both average on-site equipment costs and per-mile gathering line costs for wells in the United States. Average equipment costs are set at \$202,000 per well, while average, per-mile gathering line costs vary by the assumed diameter of the line. ICF reports average per inch-mile in 2015 for 4, 6, and 8 inch gathering lines as \$36,244, \$30,313, and \$31,631 respectively.

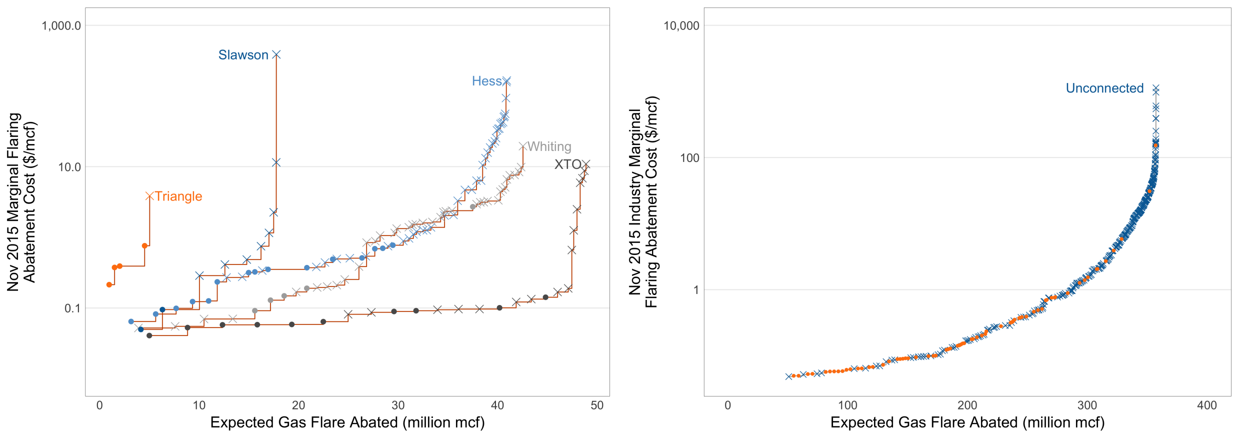
We must determine two factors to estimate each well's gathering line costs: (i) the distance to the pipeline system; and (ii) the diameter of the line. For the former, we calculate the minimum distance from a well to another gathering line or a natural gas pipeline using the data from Rextag.[30] For the latter, we use data on existing gathering line diameters and estimate an ordered probit model of pipeline's diameter as a function of each well's initial gas production and connection month.[31] Firms' MAC curves change from month-to-month

[29]Fixed costs include dehydrators, compressors, and other technologies that remove hazardous pollutants like hydrogen sulfide.

[30]Because we only observe a snapshot of the pipeline network, we do not capture how gathering line distance may change over time. Since we consider our counterfactual over an eighteen-month horizon, a one time snapshot of the pipeline network is likely a close approximation.

[31]We describe our pipeline cost construction in greater detail in Appendix B.

Figure 5: Marginal flaring abatement cost curves.



(a) Observed Connection Decisions (b) Observed Industry MAC Curve

Notes: The left figure graphs MAC curves for five firms in November 2015 and their well connection decisions in that month. The left figure graphs the industry MAC curve in November 2015. Orange circles indicate wells that are connected and orange X's indicate wells that are left unconnected.

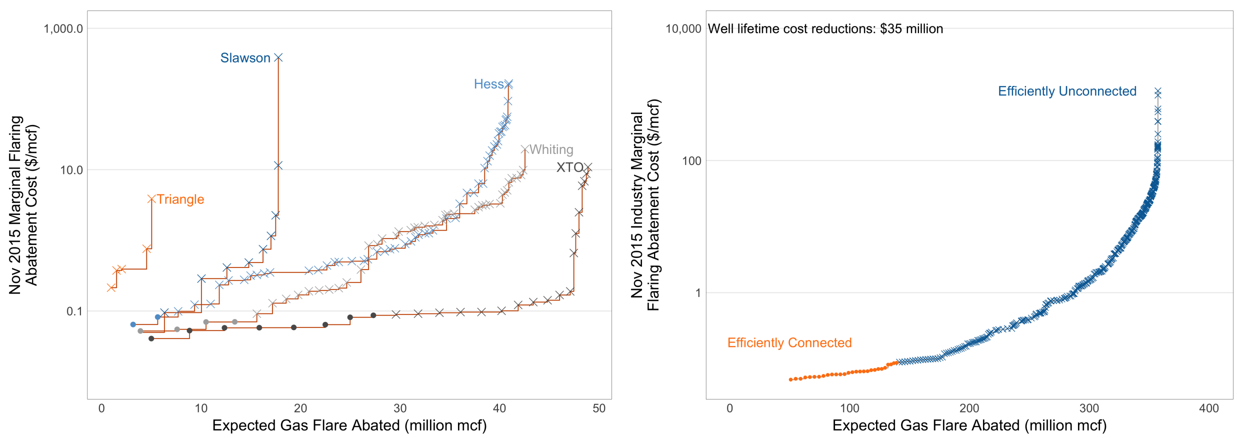
due to several factors. First, new wells come online. Second, existing wells are connected to gas capture infrastructure and are removed from future MAC curves. Third, expected lifetime gas sales g_i decreases as a well ages. Finally, the installed gathering line diameter is a decreasing function of the age of the well at connection time.[32]

After calculating equation (11) for every unconnected well in month t, we construct firm MAC curves by ordering all wells owned by a firm by their costs. Figure 5a graphs an example of five firms' MAC curves in November 2015. Circles indicate wells that were connected in November 2015, and X's indicate wells that were left unconnected. Consistent with our theoretical model, firms mostly connect their lowest cost wells and leave high-cost wells unconnected. In general, more productive wells, those with the largest horizontal gaps, also tend to be low-cost wells. This is consistent with firms clustering in productive oil and gas regions with nearby gas capture infrastructure. More unproductive wells' typically have high connection cost wells. These may be exploratory wells, and they are typically far from existing gas capture infrastructure.

Figure 5a highlights clear heterogeneity in MAC curves across the five firms. Hess, Whiting, and XTO own many wells with low connection costs and high gas production. Triangle and Slawson own fewer wells, and the wells that they own are typically less productive and have higher connection costs. Figure 5b aggregates the MAC curves across all firms. As

[32]Connection month is the strongest predictor of gathering line diameter in our ordered probit model. Predicted gathering line diameters are 8" for the first nine months, decrease to 6" if the well is connected 10 to 12 months after initial production, and decrease to 4" after that.

Figure 6: Marginal flaring abatement cost curves under efficient policy.



(a) Efficient Connection Decisions (b) Efficient Industry MAC Curve

Notes:The left figure graphs counterfactual connection decisions of five firms in November 2015 under an efficient policy. The right figure graphs the efficient connection decisions at the industry level. Orange circles indicate wells that are connected and orange X's indicate wells that are left unconnected.

before, connected wells are denoted by orange dots, and unconnected wells are denoted by blue X's. Industry-wide, many cheap wells were left unconnected while several costly wells were connected to gas capture infrastructure.

6.2 Counterfactual Policy Simulations

We now use our estimated firm and industry MAC curves to compare three counterfactual compliance scenarios and compare them to firms' observed connection decisions and abatement costs over the first eighteen months of the regulation. Here we describe our three scenarios and discuss our findings. Appendix B in the appendix contains more details on how we compute the counterfactuals.

Our first counterfactual, *inter-firm trading*, considers the gains from allowing inter-firm trading within a month but requires the counterfactual total industry abatement to equal the observed total industry abatement every month. The exercise isolates potential gains from inter-firm trade. The outcome would be achieved by instituting a cap-and-trade program with a time-varying cap and no banking or borrowing, or a time-varying flaring tax. Figures 6a and 6b illustrate this exercise graphically for one month. In the counterfactual, Triangle does not connect any of its wells, while all other firms connect just a few wells to achieve the same flaring reduction. Figure 6b illustrates this in the aggregate.

Our second counterfactual, *within-firm banking and borrowing* allows greater flexibility in the timing that firms connect wells, but re-institutes a ban on inter-firm trading, requiring

Table 5: Least-cost counterfactual simulation results.

	Relative Cost Savings	Absolute Cost Savings (Million $)
Scenario 1: Inter-Firm Trading	45%	$816
Scenario 2: Within-Firm Banking and Borrowing	25%	$479
Scenario 3: Inter-Firm Trading with Banking and Borrowing	46%	$829

each firms' total counterfactual abatement to equal its observed total abatement over the eighteen month window. This outcome can be achieved under a firm-specific cap-and-trade program with fully flexible banking and borrowing, or a firm-specific flaring tax.

Our final counterfactual, *inter-firm trading with banking and borrowing* combines the previous two and allows for both inter-firm and inter-temporal flexibility. This is equivalent to an industry cap-and-trade program with unlimited banking and borrowing, or an industry flaring tax.

Table 5 presents the absolute and relative cost savings from the three counterfactual simulations. For reference, we estimate that from January 2015 through June 2016, the oil and gas industry in North Dakota captured 3.3 billion mcf of gas at the cost of $1.82 billion. The first column shows that allowing inter-firm trading reduces compliance costs by 46%, saving $829 million. The month-specific taxes that achieve the same counterfactual flaring reductions range from $0.15/mcf in January 2015 to a high of $1.66/mcf in May 2016. The second column shows that allowing firms to bank and borrow reduces costs by 25%, or $479 million. For this second counterfactual, the firm-specific taxes that achieve the same counterfactual flaring reductions for every firm, varies between $0.14/mcf and $42.53/mcf. For reference, a $42.53/mcf tax on natural gas is equivalent to $803/tCO$_2$ carbon tax.[33] This illustrates the large differences in marginal compliance costs across firms even after allowing for unlimited within-firm banking and borrowing of flaring.

The final column of Table 5 presents gains from moving to the most flexible regulation – an industry tax on flared gas or an industry cap-and-trade program with full banking and borrowing. This would reduce compliance costs over the eighteen month window by 46%, or $829 million, only one percentage point more than if intertemporal banking and borrowing of permits was turned off. The calculated tax that would achieve this reduction is $1.35/mcf. To put the value in perspective, this is three times larger than the average public lands

[33]We use the average carbon intensity of natural gas. Propane and butane have carbon intensities about 15% higher.

royalty rate on gas revenues over this period (\$0.45/mcf). Alternatively, this amounts to a carbon tax of about \$26/tCO_2, slightly below current estimates of the social cost of carbon.

Most of the efficiency gains from moving to a market-based regulation come from inter-firm trading of flaring rights. This can be seen in the actual cost reduction numbers where Scenario 1 achieves almost all the cost reductions of Scenario 3. It can also be seen in the counterfactual flaring taxes under the three scenarios. The month-specific optimal flaring taxes in Scenario 1 are very close to the optimal flaring tax in Scenario 3, indicating that marginal compliance costs are close to equalized across firms and over time even without intertemporal banking and borrowing of flaring rights. Conversely Scenario 2 still results in flaring taxes that may vary by over \$40/mcf across firms suggesting that there are still substantial efficiency gains from inter-firm trade left on the table.

7 Conclusions and Discussion

We use rich, well-level data on oil firms' operations in North Dakota to study the effects and efficiency of a new regulation aimed at reducing gas flaring in the state. Our results suggest that the regulation has been effective. Well operators have reduced flaring rates 4 to 7 percentage points, and we attribute between one-third and one-half of the observed year-on-year reduction in flaring at new wells to the regulation. The primary mechanism that firms comply is by connecting wells to gas capture infrastructure more quickly than they did historically.

While the regulation was effective at reducing flaring in the state, we find substantive costs from abatement misallocation caused by heterogeneous compliance costs and the regulation being enforced uniformly across firms. Using a counterfactual exercise based on estimated MAC curves, we show that reallocating abatement from high- to low-cost firms would reduce aggregate compliance costs considerably. Moreover, using our preferred estimates, taxing flared gas at the social cost of carbon would achieve around the same aggregate flaring reduction at substantially lower cost. The findings highlight a key feature of oil and gas production in North Dakota that discourages flaring – firms pay royalty and taxes only on sold gas in the first year of production.

Our results are subject to several important caveats. We rely on reduced-form methods to estimate the average treatment effects of the regulation. We assume, conditional on our controls, that firms' production and flaring decisions over the first production year at wells completed after 2015 would have been similar as their choices for wells completed in 2014 but for the NDIC flaring order. However, economic conditions changed dramatically over this period – Clearbrook oil prices crashed from just under \$100/bbl in the first half of 2014 to $50 to $60/bbl in 2015 and even lower in early 2016. We use flaring data from wells in the Montana side of the Bakken in difference-in-differences and triple differences strategies to address this in Appendix C and find even larger impacts of the flaring regulation. However, the unstable economic environment changed many aspects of firms decision making over this period and may still bias our results.

We also make many simplifying assumptions to construct our MAC curves in Section 6. For example, we assume that firms receive the same gas price once they connect to gas capture infrastructure; predict gathering line diameter as a function of observable well characteristics; assume the gathering line distance is the shortest distance to an existing line; assume that right-of-way costs are minimal; use a uniform cost for wells' on-site infrastructure and per-mile gathering line costs; assume away any forward-looking behavior by firms; and assume that the natural gas processing sector in North Dakota is competitive. We explore the sensitivity of some of these choices in Appendix B. While the level of cost savings differs when we vary, for example, gathering line costs, the relative cost savings are of the same magnitude. However, due to data limitations, we are unable to account for all of these concerns. In general, we argue that most of our assumptions result in us underestimating the extent of cost heterogeneity across firms and fully addressing these limitations would only increase the value of flexibility in meeting the NDIC flaring requirements.

Future research may explore any number of these and other issues. For example, recent work studying the Texas and North Dakota oil and gas industries shows that bankruptcy protections shifts industry structure towards smaller firms (Boomhower, 2016; Lange and Redlinger, 2018). Small firms may also take advantage of the benefits of limited liability in the North Dakota shale fields. The introduction of new, stringent flaring standards may increase capital costs. If the larger upfront costs affect entry decisions, the new standard may have the effect of pricing capital constrained firms out of the market. Alternatively, future research could allow for strategic decision-making by firms, take advantage of the feature that connecting to gas capture infrastructure requires large upfront costs and forward-looking behavior, or allow for strategic investments in gas capture and processing infrastructure.

References

Abadie, A. and G. Imbens (2011). Bias-corrected matching estimators for average treatment effects. *Journal of Business and Economic Statistics 29*(1), 1–11.

Anderson, S., R. Kellogg, and S. Salant (2016). Hotelling Under Pressure. Working Paper.

Avalos, R., T. Fitzgerald, and R. Rucker (2016). Measuring the effects of natural gas pipeline constraints on regional pricing and market integration. *Energy Economics 60*, 217–231.

Bailey, A. (2015). NDPA Director Analysis Reveals Bakken Breakeven Pricing. *The Bakken Magazine.* September 16, 2015.

Bartik, A., J. Currie, M. Greenstone, and C. Knittel (2017). The Local Economic and Welfare Consequences of Hydraulic Fracturing. Working Paper.

Baumol, W. J. and W. E. Oates (1988). *The Theory of Environmental Policy.* Cambridge University Press.

Boomhower, J. (2016). Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk. Working Paper.

Brandt, A. R., T. Yeskoo, M. S. McNally, K. Vafi, S. Yeh, H. Cai, and M. Q. Wang (2016). Energy intensity and greenhouse gas emissions from tight oil production in the bakken formation. *Energy & Fuels 30*(11), 9613–9621.

Bureau of Land Management (2016). Proposed Rule: Waste Prevention, Production Subject to Royalties, and Resource Conservation. *Federal Register 81*(25), 6616–6686.

Carlson, C., D. Burtraw, M. Cropper, and K. L. Palmer (2000). Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade? *Journal of Political Economy 108*(6), 1292–1326.

Covert, T. (2015). Experiential and Social Learning in Firms: The Case of Hydraulic Fracturing in the Bakken Shale. Working Paper.

Energy Information Administration (2015). Hydraulic Fracturing Accounts for about Half of Current U.S. Crude Oil Production. Today in Energy, March 15, 2016.

Energy Information Administration (2016a). International Energy Statistics.

Energy Information Administration (2016b). Natural gas flaring in North Dakota has declined sharply since 2014. Today in Energy, June 13, 2013.

Fetkovich, M. (1980). Decline Curve Analysis using Type Curves. *Journal of Petroleum Technology 32*(6), 1065–1077.

Feyrer, J., E. Mansur, and B. Sacerdote (2017). Geographic Dispersion of Economic Shocks: Evidence from the Fracking Revolution. *American Economic Review 107*(4), 1313–1334.

Fowlie, M., C. R. Knittel, and C. Wolfram (2012). Sacred Cars? Cost-Effective Regulation of Stationary and Nonstationary Pollution Sources. *American Economic Journal: Economic Policy 4*(1), 98–126.

Gaswirth, S., K. Marra, T. Cook, R. Charpentier, D. Gautier, D. Higley, T. Klett, M. Lewan, P. Lillis, C. Schenk, M. Tennyson, and K. Whidden (2013). Assessment of undiscovered oil resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota. U.S. Geological Survey Fact Sheet 2013–3013.

Gopalakrishnan, S. and H. Klaiber (2014). Is the Shale Energy Boom a Bust for Nearby Residents? Evidence from Housing Values in Pennsylvania . *American Journal of Agricultural Economics 96*(1), 43–66.

Hausman, C. and R. Kellogg (2015). Welfare and Distributional Implications of Shale Gas. *Brookings Papers on Economic Activity Spring*, 71–125.

Hill, E. (2015). Impacts of Shale Gas Development on Ambient Air Pollution and Infant Health in Texas. Working Paper.

ICF International (2016). North American Midstream Infrastructure through 2035: Leaning into the Headwinds . *INGAA Foundation Report, Prepared by ICF International* April 12, 2016.

ICF International (2018). North American Midstream Infrastructure through 2035: Significant Development Continues. *INGAA Foundation Report, Prepared by ICF International* June 18, 2018.

Kellogg, R. (2011). Learning by Drilling: Interfirm Learning and Relationship Persistence in the Texas Oilpatch. *The Quarterly Journal of Economics 126*(4), 1961–2004.

Kerr, S. and R. Newell (2003). Policy-Induced Technology Adoption: Evidence from the U.S. Lead Phasedown. *The Journal of Industrial Economics 51*(3), 317–343.

Lange, I. and M. Redlinger (2018). Effects of Stricter Environmental Regulations on Resource Development. Working Paper.

Montgomery, W. D. (1972). Markets in Licenses and Efficient Pollution Control Programs. *Journal of Economic Theory 5*(3), 395–418.

Muehlenbachs, L., E. Spiller, and C. Timmins (2015). The Housing Market Impacts of Shale Gas Development. *American Economic Review 105*(12), 3633–3659.

Newell, R., B. Prest, and A. Vissing (2016). Trophy Hunting vs. Manufacturing Energy: The Price-Responsiveness of Shale Gas. RFF Discussion Paper 16-32.

North Dakota Industrial Commission (2015). Order 24665. Technical report.

North Dakota Industrial Commission (2016). North Dakota Monthly Oil Production Statistics.

Olmstead, S., L. Muehlenbachs, J.-S. Shih, Z. Chu, and A. Krupnick (2013). Shale Gas Development Impacts on Surface Water Quality in Pennsylvania. *Proceedings of the National Academy of Sciences 110*(13), 4962–4967.

Salmon, R. and A. Logan (2013). Flaring Up: North Dakota Natural Gas Flaring More than Doubles in Two Years. Ceres Research Report. July 2013.

Storrow, B. (2015). Could North Dakota be a Model for How to Reduce Flaring? *The Casper Star Tribune.* March 10, 2015.

Swanson, A. (2014). America's Oil Boom is Visible from Space. *The Washington Post.* October 20, 2014.

Vissing, A. (2016). One-to-Many Matching with Complementary Preferences: An Empirical Study of Natural Gas Lease Quality and Market Power. Working Paper.

World Bank (2015). Zero Routine Flaring by 2030.

Zirogiannis, N., J. Alcorn, J. Rupp, S. Carley, and J. D. Graham (2016). State Regulation of Unconventional Gas Development in the U.S.: An Empirical Evaluation. *Energy Research & Social Science 11*, 142–154.

Online Appendix for

Costs of Inefficient Regulation: Evidence from the Bakken

Gabriel E. Lade and Ivan Rudik

July 13, 2018

A Additional Summary Statistics

Table A.1 presents summary statistics, disaggregated by the pre- and post-regulation. Production, fracking input use, and total well depth increased between the two periods. Gas flaring rates in the first year of production fell from 34% in 2012–2014 to 22% in 2015–2016. Flaring rates are lower at connected wells, but are non-zero and similar across wells completed before and after the regulation.[34] The decrease coincides with shorter gas connection times. Oil and gas prices vary substantially over the sample. Average Clearbrook and HH prices were $89/bbl and $3.80/mcf in 2012-2014, respectively. Both fell considerably in 2015 to mid-2016, averaging $43/bbl and $2.55/mcf.

Table A.1: Summary statistics.

		Mean	Median	Std. Dev.
2012-2014	Oil Production in 1st Year (bbls/day)	297.89	222.77	280.28
	Gas Production in 1st Year (mcf/day)	328.90	219.33	391.87
	Water Products Injected (1000 gals)	3,093.36	2,479.55	2,320.94
	Non-Water Products Injected (1000 gals)	3.44	0.00	22.79
	Well Depth (ft)	20,081.55	20,496.00	1,615.49
	Flaring in 1st Year: All Wells (%)	0.34	0.11	0.40
	Flaring in 1st Year: Connected Wells (%)	0.21	0.05	0.30
	Time to Gas Connection (Months)	3.51	2.00	4.93
	Distance from Pipeline (miles)	N/A	N/A	N/A
	Clearbrook Oil Price ($/bbl)	89.21	90.99	10.72
	Henry Hub Price ($/mcf)	3.89	3.94	0.49
2015-2016	Oil Production in 1st Year (bbls/day)	377.80	297.10	318.36
	Gas Production in 1st Year (mcf/day)	514.97	372.70	506.57
	Water Products Injected (gals)	4,516.25	3,539.84	4,609.35
	Non-Water Products Injected (gals)	866.73	0.00	11057.80
	Well Depth (ft)	20,351.90	20,690.00	1,630.16
	Flaring in 1st Year: All Wells (%)	0.22	0.06	0.31
	Flaring in 1st Year: Connected Wells (%)	0.17	0.05	0.25
	Time to Gas Connection (Months)	1.73	1.00	1.39
	Distance from Pipeline (miles)	0.38	0.12	0.89
	Clearbrook Oil Price ($/bbl)	43.24	42.81	7.81
	Henry Hub Price ($/mcf)	2.72	2.85	0.28

[34]Flaring at connected wells is typically the result of issues with or excess pressure in pipelines, or to natural gas plants operating at or near capacity.

B Simulation Details

B.1 Pipeline Costs

We take advantage of data on pipeline locations and characteristics from Rextag to estimate pipeline costs. Here, we discuss in greater detail how we construct each component of every well's per unit connection costs. Average gathering costs for well i are given by equation (11), specified again below for ease of exposition:

$$\frac{C_i}{g_i} = \frac{(\text{On-site Fixed Costs}) + (\text{Inch-Mile Line Costs}) \times d_i \times w_i}{g_i}.$$

where C_i is the gathering line cost, d_i is the gathering line distance, w_i is the gathering line diameter, and g_i is well i's lifetime gas production.

We estimate the on-site and pipeline costs as follows:

$$C_i = F + \xi_i \times d_i \times w_i$$

where F are the estimated fixed costs and are fixed across all wells, ξ_i is the per inch-mile gathering line cost which varies across well as described below, d_i is the estimated gathering line distance, and w_i is the predicted gathering line diameter.

On-site fixed costs: ICF International uses estimated oil and gas lease equipment and operating costs from the Energy Information Administration to estimate average, on-site equipment costs for gas-processing. The equipment includes dehydrators, compressors, and equipment to remove hazardous pollutants on-site. Table B.1 reports the costs. Our main estimates are from the most recent ICF report, released in 2018, though we also report results in this Appendix from an earlier 2016 report.

Table B.1: Engineering estimates of gathering line costs.

Report Year	2016	2018
Lease Equipment	\$250,000	\$202,000
4" Gathering Line (\$/inch-mile)	\$34,467	\$36,244
6" Gathering Line (\$/inch-mile)	\$28,827	\$30,313
8" Gathering Line (\$/inch-mile)	\$30,080	\$31,631

Sources: ICF International (2016, 2018)

Pipeline diameter costs: Pipeline costs per inch-mile ξ_i vary by gathering line diameter. We use data reported by ICF, International to assign gathering line costs. Table B.1 reports

Table B.2: Pipeline Diameters

Diameter (inches)	Frequency	Percent	Cumulative
4	9	4.79	4.76
6	39	20.74	25.40
8	140	74.47	100

estimated per inch-mile gathering line costs from ICF International (2016, 2018) for diameters we assign to wells in our data. Costs from both reports are for gathering line laid in 2015.

We use data on gathering line diameters from Rextag to predict each well's gathering line diameter as a function of the well's initial gas production and the production month that it is connected. The data from Rextag are limited – only 188 of the roughly 3,300 wells in our sample have non-missing diameter data. Table B.2 reports the frequency of each pipeline diameter in our data.[35] Around 75% of wells are connected to 8" gathering lines, just over 20% are connected to 6" lines, and the remaining 5% are connected to 4" lines.[36]

Figure B.1 graphs the correlation between pipeline diameter and wells' initial gas production and the production month in which the well was connected to gas capture infrastructure. Most 4" lines are connected to lower production wells, while the highest producing wells are almost always connected to 8" gathering lines. Also, most wells connected in the first production month are connected to 8" gathering lines, while wells connected after their fourth production month are more likely to be connected to 6" gathering lines.

We use an ordered probit model to predict wells' gathering line diameters as a function of initial gas production and the production month that the well is connected to gas capture infrastructure. Specifically, we specify the probability of observing well i being connected to a gathering line with diameter $j = \{4, 6, 8\}$ as:

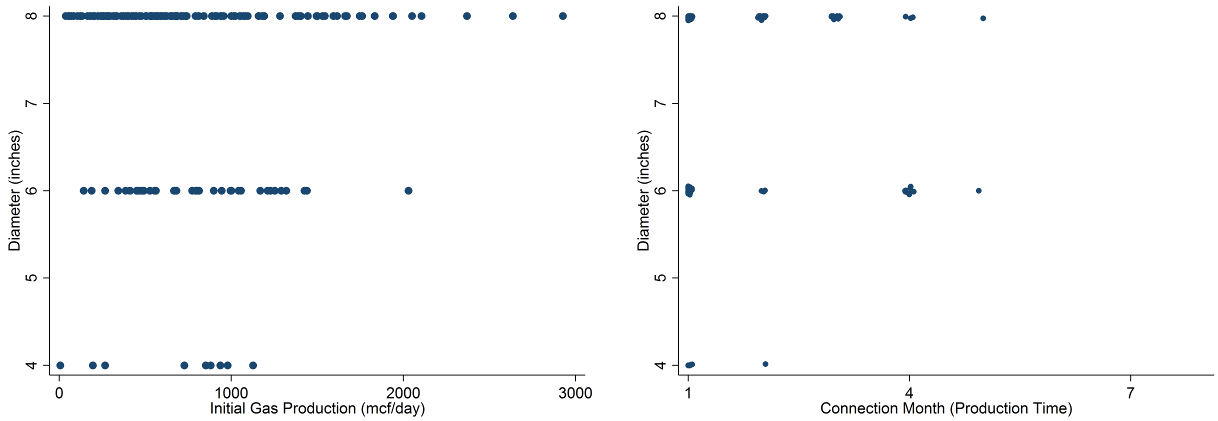
$$\begin{aligned}
\Pr(y_i = 4) &= \Phi(\kappa_0 - \mathbf{x}_i\beta) \\
\Pr(y_i = 6) &= \Phi(\kappa_1 - \mathbf{x}_i\beta) - \Phi(\kappa_0 - \mathbf{x}_i\beta) \\
\Pr(y_i = 8) &= 1 - \Phi(\kappa_1 - \mathbf{x}_i\beta),
\end{aligned}$$

where $\mathbf{x}_i$ are the well characteristics. We estimate our parameters of interest (κ_i and β) using maximum likelihood estimation with robust standard errors.

[35] We exclude three observations that had 3" diameters, three that had 10" diameters, and two that had 12" diameters since they are non-standard sizes. We also exclude a single well that was connected a year after initial production.

[36] ICF International (2018) reports that average gathering line diameters in North America from 2013 to 2017 was 6.4". Our average diameter is slightly higher, 7.3".

Figure B.1: Gathering line diameter, gas production, and connection month



(a) Diameter and Initial Gas Production

(b) Diameter and Connection Month

Notes: Figure B.1a graphs the correlation between each well's initial gas production and it's pipeline diameter. Figure B.1b graphs the correlation between each well's connection month to gas capture infrastructure, specified in production time, and the gathering line diameter.

Table B.3 reports our results. Column (1) estimates the model as a function of wells' initial gas production, column (2) as a function of connection month, and column (3) as a function of both. As expected, wells with high initial gas production have a higher probability of being connected to a larger gathering line, while wells that are connected later in their productive lifetimes have a lower probability of being connected to a larger gathering line. Similar comparative statics hold when we include both covariates in the regression.

We use the estimates from column (3) to predict the probability of each well being connected to 4", 6", and 8" gathering lines as a function of the wells' initial production and production month. We assign the diameter with the highest predicted probability as the wells' gathering line diameter in the simulations. In column (3), the connection timing has a larger impact on the diameter than initial gas production. This is evident in our predicted gathering line sizes. All wells connected before their ninth production month are assigned an 8 inch gathering line, those connected in months 10 to 12 are assigned a 6 inch gathering line, and those connected after the first year are assigned a 4 inch gathering line.

Table B.3: Gathering Line Diameter Regressions

	(1)	(2)	(3)
Initial Gas Production (mcf/day)	0.000036	–	0.000005
	(0.0002)	–	(0.0002)
Connection Month	–	-0.124	-0.123
	–	(0.080)	(0.080)
κ_0	-1.638***	-1.859***	-1.854***
	(0.214)	(0.239)	(0.287)
κ_1	-0.630***	-0.849***	-0.844***
	(0.165)	(0.168)	(0.216)
Observations	188	188	188

Notes: The table presents estimated coefficients from an ordered probit model. The dependent variable is gathering line diameter (4, 6, or 8 inches). Connection month is specified in production time. Standard errors in all regression equations are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Distance to pipeline network (d_i): We use geospatial data from Rextag on the location of all natural gas pipelines in North Dakota to estimate the distance between every unconnected well and the nearest pipeline. We assume the shortest distance equals d_i, the distance that the gathering line must be built. Wells completed since 2015 are, on average, 0.4 miles from the nearest pipeline. However, distribution of distance is highly skewed. The median well is only 0.12 miles from the pipeline network, the 95th percentile is 1.6 miles from a pipeline, and the 99th percentile is over 6 miles from a pipeline.

B.2 Counterfactual Algorithm

Inter-firm trading Our first counterfactual scenario considers the gains from allowing inter-firm trading within a month/compliance period, but requires the same counterfactual flaring abatement within every compliance period as the observed flaring abatement. This exercise isolates potential gains from inter-firm trade.

We compute the counterfactual compliance scenario for every month starting from January 2015 to June 2016 as follows:

1. For every month, compute the observed total abatement (captured gas).
2. Starting in January 2016, order all wells by their MAC. Compute the least-cost connection decisions to achieve the same flaring reduction observed in that month.

3. Carry forward all wells that were not connected in the counterfactual, recompute their expected lifetime gas production, and add any new wells that begin producing in that month to the counterfactual industry MAC curve. Compute the least-cost connection decisions to achieve the same, monthly observed abatement.

4. Repeat step 3 through June 2016.

Within-firm banking and borrowing Our second counterfactual allows greater flexibility in the timing that firms connect wells, but re-institutes a ban on inter-firm trading. For this, we take advantage of the fact that, given a sufficiently long time horizon, a firm-specific cap-and-trade program with fully flexible banking and borrowing is equivalent to a firm-specific tax on flaring.

For each firm, we compute the following:

1. Compute the total volume of gas captured by firm j from January 2015 to June 2016.

2. Search for some constant t_j^* such that when all unconnected wells owned by firm j with MACs below t_j^* are connected in the first month that their MAC is below t_j^*, the total amount of gas captured over the full horizon equals the observed amount of gas captured by firm j.

This counterfactual induces individual firms to capture the same amount of gas as in reality but allows flexibility in the timing of gas capture.

Inter-firm trading with banking and borrowing Last, we allow for both inter-firm and inter-temporal flexibility. As in the previous scenario, we take advantage of the equivalence between a flaring tax t^{**} and an industry cap-and-trade program with unlimited banking and borrowing.

For the entire industry, we compute the following:

1. Compute the total volume of gas captured by all firms from January 2015 to June 2016.

2. Search for some constant t^{**} such that when all unconnected wells with MACs below t^{**} are connected in the first month their MAC is below t^{**}, the total amount of gas captured over the full horizon is equal to the observed amount of gas captured by the industry.

The value t^{**} can be interpreted as the permit price in the tradable permit system with banking and borrowing or as an industry-wide flaring tax.

B.3 Additional Simulation Results

Table B.4: Sensitivity analysis of counterfactual cost and production parameters.

	4 Inch Pipe	6 Inch Pipe	8 Inch Pipe
Half Fixed Cost	39%, 44%, \$0.72/mcf	44%, 49%, \$1.26/mcf	47%, 53%, \$2.21/mcf
Base Fixed Cost (\$202,000)	32%, 36%, \$0.87/mcf	39%, 44%, \$1.37/mcf	44%, 49%, \$2.35/mcf
Double Fixed Cost	25%, 28%, \$1.15/mcf	32%, 36%, \$1.69/mcf	38%, 43%, \$2.55/mcf

Notes: The first entry in each cell is the cost reduction from the inter-firm trading counterfactual scenario. The second entry in each cell is the cost reduction from the inter-firm trading and banking and borrowing counterfactual scenario. The third entry in each cell is the cost-effective flaring tax associated with the second entry. Divide by 0.053 tCO_2/mcf to convert into an equivalent carbon tax. Our base parameterization is a 20 year production horizon, pipe diameter as a function of production time, and the base fixed cost.

Table B.4 displays sensitivity check results for our counterfactual. We check the sensitivity of our results on two margins. First we vary the fixed cost component to be double or half the base value. Second, we vary the gathering pipeline diameter used to be 4, 6, or 8 inches for all wells instead of having the diameter be a function of production time. The first value in each cell is the relative cost reduction from the inter-firm trading scenario, the second value is the relative cost reduction from the inter-firm trading with banking and borrowing scenario, and the third value is the cost-effective flaring tax for inter-firm trading with banking and borrowing. Relative cost savings can range from one-quarter to one-half of our estimates of the cost of the observed connection decisions, and the cost-effective flaring taxes range from half to double our estimate in the main text.

C Sensitivity Analyses and Robustness Checks

C.1 Flaring Treatment Effects

Alternative North Dakota control wells. We first test the sensitivity of our flaring results, reported in Table 1, to specifying alternative control wells using data from North Dakota. We explore three alternative control well specifications: (i) wells completed between January and August 2014; (ii) wells completed from 2013–2014; and (iii) wells completed in 2013. The first and third specifications, in particular, are meant to address concerns that wells drilled just before the policy may have altered their flaring decisions in anticipation of the upcoming regulation.

Table C.1 reports the results. Results are largely similar to our main specification, and where the results do differ, the estimated impact of the flaring regulation is typically larger. Figure C.1 graphs the corresponding flexible difference-in-difference results using the same controls as in Panels A and B for all wells. We observe the same pattern as in Figure 3a, where firms reduced flaring the most in the first four to six months of production, after which flaring rates are largely the same across wells subject to the regulation and those that were not.

Alternative control wells: Montana data. Another concern is that, even after including our set of covariates, wells completed before 2015 serve as a poor counterfactual group for those completed after 2015. While we control for both production and price controls, they may not sufficiently control for differences in the economic environment pre- and post-2015 given the large decline in oil prices over this period. We explore the sensitivity of our results to these concerns using well-level flaring data from the Montana Board of Oil and Gas Conservation.[37] The data include wells that were completed in the Montana side of the Bakken/Three-Forks formation over our period.[38] We then use difference-in-differences and triple differences research designs to study the impact of the regulation on well-level flaring rates. A well is treated in the difference-in-difference model if it is completed after 2015 in North Dakota, while a well is treated in the triple difference model if it is completed after 2015 in North Dakota, and it has passed its fourth production month. The strategy should address our concerns so long as Montana wells drilled in the Bakken were similarly affected by oil price declines over this period.[39]

[37] Data are available at `http://bogc.dnrc.mt.gov/WebApps/DataMiner/`.

[38] Flaring statistics are reported by the Montana Board or Oil and Gas Conserve ration at the lease level. To maintain our analysis at the well-level, we restrict the Montana data to single-well leases.

[39] Montana has a historic flaring regulation enacted in 1978 that requires firms to limit gas production to 100 mcf/day if the well is flaring more than 100 mcf/day of gas after 60 days. This rule has been in effect and unchanged since enactment.

Table C.2 reports the results. We find larger impacts of the regulation in both the difference-in-differences triple differences models. After controlling for differences in well productivity, we find that wells completed after 2015 flared 11% less in North Dakota than those drilled in Montana over the first year of production. If we limit our attention to after wells must comply with the flaring regulation, wells completed in North Dakota flare on average 2% less than those in Montana in their fourth to twelfth production month. A key limitation of this empirical approach, however, is statistical power. Firms are much less active in the Montana side of the Bakken formation. As such, we observe only 62 wells drilled in Montana over this period. Nonetheless, the results here provide further support for our main empirical strategy.

Placebo tests. We also perform a number of placebo regression tests to further support our research design. We define the first placebo treatment group as wells completed in 2014, where the control group are wells completed in 2013, shifting back the treatment and control definitions by a year. For the second placebo, we shift the control and treatment designations back by another year, where we define treated wells as those completed in 2013 and controls as those completed in 2012. Because the regulatory environment did not change between these two pairs of year, we would not expect to define a treatment effect.

Table C.3 reports the results. We find significant flaring reductions associated with the placebo treatment effects in the differences and nearest neighbor estimators. This suggests that we may omit some relevant well characteristics in comparing flaring rates in production time from year-to-year. However, we find no impact of the regulation in the difference-in-difference estimators – supporting our research design. Figure C.2 presents corresponding flexible difference-in-difference results. The 2014 placebo results show no statistically significant differences in flaring rates in production time, and the estimates are most often close to zero. In contrast, the 2013 results show no large differences in flaring rates in the first nine production months, while flaring rates increase substantially in months 10 to 12.

C.2 Mechanisms

Spud-to-completion. Table C.4 explores the sensitivity of our spud-to-completion time duration models. As in the flaring regressions above, we test the sensitivity of our estimates to redefining the control group in three ways. All estimates are similar to those in Table 2, or generally larger.

Connection-time duration. Table C.5 explores the sensitivity of our connection time duration models to using alternative control groups. As with the flaring regressions, where differences arise, we find larger treatment effects. Table C.6 contains estimates from regressions exploring the timing of firms' gas capture connection decisions to test whether the regulation leads to firms connecting to gas capture infrastructure in specific months. For this, we estimate linear probability models testing whether firms completed after 2015 were more likely to connect in the first production month, the first four production months, and the fourth production month conditional on entering the fourth production month unconnected. The regressions more directly test whether the regulation impacts the timing of firms' connection decisions. Conditional on our controls, wells are 10%–12% more likely to connect in the first month of production or the first four months of production, respectively. Conditional on not having connected before month 4, wells completed in 2015 are over 50% more likely to connect a well in the fourth production month when the well is included in the firm flaring rate. This is consistent with the results in the KM estimates from Figure 4b.

Oil and gas production. Table C.7 and Table C.8 present similar sensitivity test results using alternative control groups for the impacts of the policy on wells' oil and gas production. The corresponding results in the main text are in Table 4. Oil production results are largely similar. However, as the comparison group includes older wells, those completed in 2013, we find larger impacts. Similar issues arise with gas production. This is likely due to older wells being less appropriate controls for 2015 wells – technological advances in oil and gas drilling have advanced rapidly over this period.

Table C.1: Average effect of the regulation on flaring rates using alternative control wells.

	(1)	(2)	(3)	(4)	(5)	(6)
	Dif	Dif	NN Match	D-in-D	D-in-D	NN Match
Panel A: Alternative Control Wells - Completed 2014, January to August						
Post-2015 (M1-M12)	-0.093***	-0.041***	-0.102***			
	(0.009)	(0.011)	(0.012)			
Post-2015 (M4-M12)				-0.028**	-0.018	-0.066***
				(0.011)	(0.012)	(0.011)
Observations	25,033	25,000	2,527	25,011	25,011	2,527
Wells	2,728	2,725	2,527	2,706	2,706	2,527
Panel B: Alternative Control Wells - Completed 2013-2014						
Post-2015 (M1-M12)	-0.129***	-0.116***	-0.130***			
	(0.007)	(0.009)	(0.008)			
Post-2015 (M4-M12)				-0.020**	-0.015*	-0.121***
				(0.009)	(0.009)	(0.007)
Observations	47,177	47,132	4,934	46,990	46,990	4,389
Wells	5,072	5,068	4,934	4,885	4,885	4,389
Panel C: Alternative Control Wells - Completed 2013						
Post-2015 (M1-M12)	-0.139***	-0.146***	-0.209***			
	(0.008)	(0.010)	(0.010)			
Post-2015 (M4-M12)				-0.018*	-0.009	-0.138***
				(0.010)	(0.010)	(0.007)
Observations	36,097	36,061	2,575	36,075	36,075	2,660
Wells	3,259	3,256	2,575	3,237	3,237	2,660
Well FE	No	No	No	Yes	Yes	No
Firm FE	No	Yes	No	No	No	No
Township FE	No	Yes	No	No	No	No
Production Month FE	No	Yes	No	Yes	Yes	No
Weather Controls	No	Yes	No	No	Yes	No

Notes: The dependent variable is the well-level flaring rate. The coefficients of interest are Post-2015 (M1-M12), which equals one if the well was completed after 2015, and Post-2015 (M4-M12), which equals one if the well was completed after 2015 and it is after the well's fourth production month. Dif, D-in-D, and NN Match denote our differences, difference-in-differences, and nearest neighbor matching estimators. Regression standard errors are clustered at the well level, and NN match standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level. Panel C NN match was based on the two nearest neighbors instead of five because of limited numbers of exactly matched wells on the number of production months observed.

Table C.2: Average effect of regulation on flaring: Montana controls.

	(1)	(2)	(3)	(4)
Post-2015 X North Dakota (M1-M12)	-0.282***	-0.116		
	(0.101)	(0.076)		
Post-2015 X North Dakota (M4-M12)			-0.022**	-0.020*
			(0.011)	(0.011)
Log Gas Production		0.032***		0.045***
		(0.002)		(0.002)
Δ Log HH Price		-0.255***		0.009
		(0.068)		(0.028)
Δ Log Clearbrook Price		-0.242***		-0.043*
		(0.051)		(0.026)
Observations	27,124	27,113	26,937	26,926
Wells	3,420	3,419	3,233	3,232
Model	D-in-D	D-in-D	DDD	DDD
Well FE	No	No	Yes	Yes
Firm FE	No	Yes	No	No
State FE	Yes	Yes	No	No
Month FE	No	Yes	No	No
Year FE	Yes	Yes	Yes	Yes
Production Month FE	Yes	Yes	No	No
Production Month X State FE	No	No	Yes	Yes
Weather Controls	No	Yes	No	Yes

Notes: The dependent variable is the well-level flaring rate. In all specifications, time is specified in production time. The coefficients of interest are Post-2015 (M1-M12) , which equals one if the well was completed after 2015 in North Dakota, and Post-2015 (M4-M12) , which equals one if the well was completed after 2015 in North Dakota and after the well's fourth production month. D-in-D and DDD denote our differences-in-differences and triple difference models, respectively. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.3: Average effect of placebo regulations on flaring rates.

	(1)	(2)	(3)	(4)	(5)	(6)
Panel A: 2014 Placebo Wells						
Post-2014 (M1-M12)	-0.151***	-0.102***	-0.137***			
	(0.010)	(0.010)	(0.027)			
Post-2014 (M4-M12)				0.001	0.009	-0.134***
				(0.011)	(0.011)	(0.029)
Observations	33,600	33,600	1,936	33,477	33,477	1,936
Wells	3,616	3,616	1,936	3,493	3,493	1,936
Panel B: 2013 Placebo Wells						
Post-2013 (M1-M12)	-0.117***	-0.066***	-0.082***			
	(0.012)	(0.011)	(0.033)			
Post-2013 (M4-M12)				0.052***	0.028**	-0.054
				(0.012)	(0.012)	(0.036)
Observations	31,246	31,203	1,779	31,111	31,111	1,779
Wells	3,377	3,373	1,779	3,242	3,242	1,779
Model	Dif	Dif	NN Match	D-in-D	D-in-D	NN Match
Well FE	No	No	No	Yes	Yes	No
Firm FE	No	Yes	No	No	No	No
Township FE	No	Yes	No	No	No	No
Production Month FE	No	Yes	No	Yes	Yes	No
Calendar Month FE	No	Yes	No	No	Yes	No
Weather Controls	No	Yes	No	No	Yes	No

Notes: The dependent variable is the well-level flaring rate. The coefficients of interest are Post-2015 (M1-M12), which equals one if the well was completed after 2015, and Post-2015 (M4-M12), which equals one if the well was completed after 2015 and it is after the well's fourth production month. Dif, D-in-D, and NN Match denote our differences, difference-in-differences, and nearest neighbor matching estimators. Regression standard errors are clustered at the well level, and NN match standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.4: Effect of the regulation on spud-to-completion duration using alternative control wells.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Panel A: Alternative Control Wells - Completed 2014, January to August					
Post-2015	0.209***	0.203***	0.183***	1.351***	1.225***
	(0.017)	(0.017)	(0.018)	(0.101)	(0.107)
Log Distance to Pipeline		-0.020***	-0.023***		
		(0.007)	(0.007)		
Non-water Inputs		-0.001	-0.003		
		(0.005)	(0.005)		
Water Inputs		0.027**	0.028**		
		(0.012)	(0.013)		
Log Total Depth of Well		0.148	0.222**		
		(0.093)	(0.095)		
Δ Log HH Price		0.777***	1.125***		
		(0.115)	(0.142)		
Δ Log Clearbrook Price		-0.585***	-0.520***		
		(0.091)	(0.105)		
Observations	18,758	18,009	17,719	2,593	2,590
Panel B: Alternative Control Wells - Completed 2013-2014					
Post-2015	0.242***	0.233***	0.281***	1.489***	1.420***
	(0.013)	(0.014)	(0.014)	(0.089)	(0.088)
Log Distance to Pipeline		-0.022***	-0.020***		
		(0.005)	(0.005)		
Non-water Inputs		-0.002	-0.004		
		(0.003)	(0.003)		
Water Inputs		0.028***	0.031***		
		(0.010)	(0.011)		
Log Total Depth of Well		0.211***	0.270***		
		(0.080)	(0.071)		
Δ Log HH Price		0.207**	-0.237**		
		(0.086)	(0.104)		
Δ Log Clearbrook Price		0.060	0.111		
		(0.070)	(0.084)		
Observations	32,372	27,245	26,955	4,153	4,149
Panel C: Alternative Control Wells - Completed 2013					
Post-2015	0.294***	0.289***	0.384***	2.074***	1.974***
	(0.015)	(0.018)	(0.020)	(0.103)	(0.116)
Log Distance to Pipeline		-0.038***	-0.036***		
		(0.007)	(0.006)		
Non-water Inputs		0.002	-0.003		
		(0.006)	(0.006)		
Water Inputs		0.053***	0.051***		
		(0.013)	(0.012)		
Log Total Depth of Well		0.041	0.105		
		(0.073)	(0.072)		
Δ Log HH Price		-0.528***	-1.079***		
		(0.101)	(0.129)		
Δ Log Clearbrook Price		-0.316***	-0.308***		
		(0.082)	(0.101)		
Observations	21,030	16,411	16,121	2,438	2,435
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is the spud-to-completion duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

Table C.5: Effect of the regulation on first production-to-connection duration using alternative control wells.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Panel A: Alternative Control Wells - Completed 2014, January to August					
Post-2015	-0.226***	-0.137***	-0.195***	-0.445***	-0.747***
	(0.043)	(0.035)	(0.037)	(0.079)	(0.103)
Log Distance to Pipeline		0.125***	0.125***		
		(0.012)	(0.012)		
Gas Production		-0.254***	-0.256***		
		(0.012)	(0.012)		
Δ Log HH Price		-0.932***	-0.112		
		(0.191)	(0.225)		
Observations	5,601	5,601	5,601	2,530	2,530
Panel B: Alternative Control Wells - Completed 2013-2014					
Post-2015	-0.408***	-0.299***	-0.296***	-0.701***	-0.859***
	(0.035)	(0.029)	(0.030)	(0.061)	(0.066)
Log Distance to Pipeline		0.138***	0.138***		
		(0.010)	(0.010)		
Gas Production		-0.287***	-0.287***		
		(0.010)	(0.010)		
Δ Log HH Price		0.617***	0.448***		
		(0.145)	(0.173)		
Observations	12,100	12,100	12,100	4,664	4,664
Panel C: Alternative Control Wells - Completed 2013					
post15	-0.612***	-0.466***	-0.498***	-0.887***	-1.144***
	(0.040)	(0.035)	(0.039)	(0.073)	(0.083)
Log Distance to Pipeline		0.148***	0.145***		
		(0.012)	(0.012)		
Gas Production		-0.289***	-0.288***		
		(0.013)	(0.013)		
Δ Log HH Price		0.185	0.131		
		(0.181)	(0.213)		
Observations	8,530	8,530	8,530	2,933	2,933
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is first production-to-connection duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

Table C.6: Effect of the regulation on gas connection probability using a linear probability model.

	(1)	(2)	(3)
Connection Month	Month 1	Months 1 to 4	Month 4
Post-2015	0.098***	0.122***	0.560***
	(0.020)	(0.014)	(0.073)
Log Initial Gas Production	0.050***	0.008*	0.038*
	(0.007)	(0.004)	(0.021)
Log Dist. to Gathering Line	-0.031***	-0.012***	-0.017
	(0.007)	(0.004)	(0.020)
Log Dif. HH Price (Connection Month)	0.244	-0.404***	-3.446***
	(0.181)	(0.106)	(0.766)
Log Dif. Clearbrook Price (Connection Month)	0.120	-0.267***	-1.654**
	(0.171)	(0.092)	(0.752)
Observations	3,243	3,243	400
Firm FE	Yes	Yes	Yes
Township FE	Yes	Yes	Yes
Calendar Month FE	Yes	Yes	Yes
Weather Controls	Yes	Yes	Yes

Notes: The dependent variable is an indicator variable for whether a well connected to gas capture infrastructure in the month(s) specified in the header. Standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.7: Average effect of the regulation on oil production using alternative control wells.

	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Panel A: Alt. Control Wells - Completed 2014, January to August				
Post-2015 (M1-M12)	-0.009	0.002	0.003	0.059*
	(0.023)	(0.023)	(0.023)	(0.034)
Log Initial Oil Production	0.278***	0.279***	0.279***	
	(0.018)	(0.018)	(0.018)	
Δ Log Clearbrook Price	-0.079	0.050	0.038	
	(0.097)	(0.100)	(0.100)	
Observations	25,033	25,033	25,033	2,572
Wells	2,728	2,728	2,728	2,572
Panel B: Alt. Control Wells - Completed 2013-2014				
Post-2015 (M1-M12)	0.034*	0.034*	0.036**	0.003
	(0.018)	(0.018)	(0.018)	(0.023)
Log Initial Oil Production	0.251***	0.251***	0.251***	
	(0.012)	(0.012)	(0.012)	
Δ Log Clearbrook Price	-0.147*		-0.110	
	(0.079)		(0.079)	
Observations	47177	47177	47177	5072
Wells	5072	5072	5072	5072
Panel C: Alt. Control Wells - Completed 2013				
Post-2015 (M1-M12)	0.073***	0.074***	0.074***	0.038
	(0.020)	(0.020)	(0.020)	(0.026)
Log Initial Oil Production	0.243***	0.243***	0.243***	
	(0.014)	(0.014)	(0.014)	
Δ Log Clearbrook Price	0.065	0.094	0.084	
	(0.097)	(0.097)	(0.097)	
Observations	36,097	36,097	36,097	2,665
Wells	3,259	3,259	3,259	2,665
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

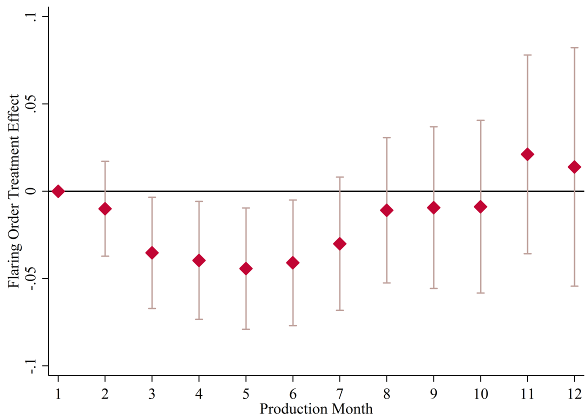
Notes: Standard errors in all regression equations are clustered at the well level, and standard errors in the NN match specifications are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.8: Average effect of the regulation on gas production using alternative control wells.

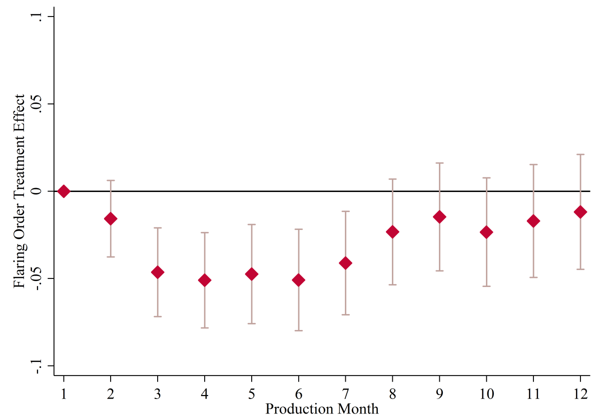
	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Panel A: Alt. Control Wells - Completed 2014, January to August				
Post-2015 (M1-M12)	0.055**	0.067**	0.067**	0.072*
	(0.027)	(0.028)	(0.028)	(0.039)
Log Initial Gas Production (mcf/day)	0.250***	0.249***	0.249***	
	(0.017)	(0.017)	(0.017)	
Δ Log HH Price	0.152	0.216	0.207	
	(0.131)	(0.133)	(0.133)	
Observations	24,604	24,604	24,604	2,527
Wells	2,683	2,683	2,683	2,527
Panel B: Alt. Control Wells - Completed 2013-2014				
Post-2015 (M1-M12)	0.141***	0.143***	0.143***	0.087***
	(0.022)	(0.022)	(0.022)	(0.025)
Log Initial Gas Production (mcf/day)	0.235***	0.235***	0.235***	
	(0.012)	(0.012)	(0.012)	
Δ Log HH Price	-0.194**	-0.192**	-0.190**	
	(0.095)	(0.096)	(0.096)	
Observations	45,843	45,843	45,843	4,934
Wells	4,934	4,934	4,934	4,934
Panel C: Alt. Control Wells - Completed 2013				
Post-2015 (M1-M12)	0.197***	0.198***	0.198***	0.114***
	(0.024)	(0.024)	(0.024)	(0.028)
Log Initial Gas Production (mcf/day)	0.231***	0.231***	0.231***	
	(0.014)	(0.014)	(0.014)	
Δ Log HH Price	0.041	0.049	0.055	
	(0.121)	(0.122)	(0.122)	
Observations	34,994	34,994	34,994	2,575
Wells	3,166	3,166	3,166	2,575
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

Notes: Standard errors in all regression equations are clustered at the well level, and standard errors in the NN match specifications are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Figure C.1: Treatment effects of the regulation on flaring rates by production month using alternative control wells.



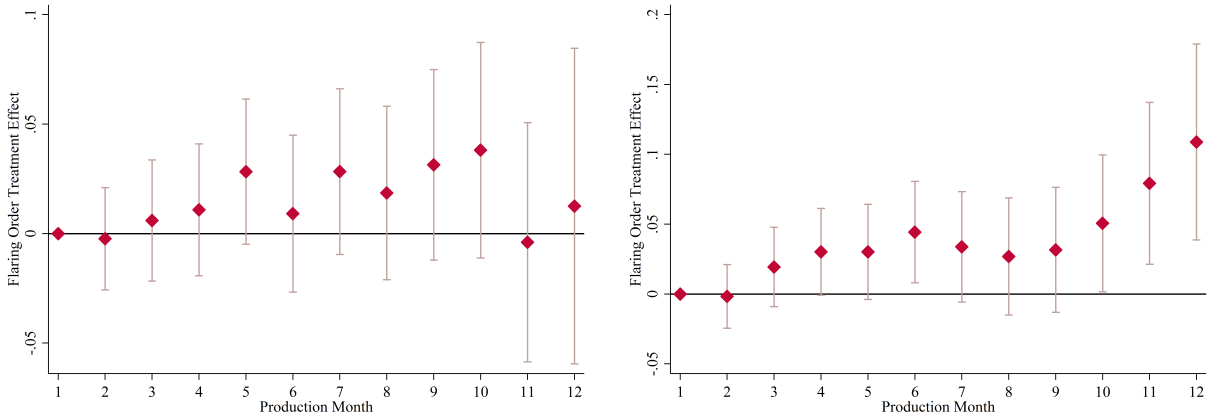
(a) Alternative Control Wells - Completed 2014, January to August



(b) Alternative Control Wells - Completed 2013-2014

Notes: Figure C.1a graphs the point estimates and 95% confidence intervals from estimating equation (7) using wells completed in January 2014 – August 2014 as the control group. Time is specified in production time, with month 1 corresponding to the first production month, and the effects are relative to the regulation's effect in the first production month. Figure C.1b graphs the point estimates and 95% confidence intervals from estimating equation (7) using wells completed in 2013 as the control group. Both regressions include the same controls as in column 2 of Table 1. Standard errors are clustered at the well level.

Figure C.2: Treatment effects of placebo regulations on flaring rates by production month.



(a) 2014 Placebo Wells - All Months

(b) 2013 Placebo Wells - All Months

Notes: Figure C.2a graphs the point estimates and 95% confidence intervals from estimating equation (6) using a placebo regulation that goes into effect in 2014 and a control group defined as wells completed in 2013. Time is specified in production time, with month 1 corresponding to the first production month, and the effects are relative to the regulation's effect in the first production month. Figure C.2b graphs the point estimates and 95% confidence intervals from estimating equation (6) using a placebo regulation that goes into effect in 2013 and a control group defined as wells completed in 2012. Both regressions include the same controls as in column 2 of Table 1. Standard errors are clustered at the well level.