Access to Capital and Investment Composition: Evidence from Fracking in North Dakota*

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Abstract

We examine the relationship between access to capital and project choice using data from the capital intensive hydraulic fracturing (*fracking*) industry. The data allow us to distinguish riskier market-expanding projects from investments in proven markets. We find that private firms more intensely invest in the former type of projects, while public firms tilt their investments towards the latter. Furthermore, we find that improving financing conditions for private firms mitigates these differences in investment patterns. Our results are consistent with anecdotal evidence that private firms tend to more aggressively push technological boundaries and suggest that access to financing contributes to this dynamic.

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"...and yet the true creator is necessity, who is the mother of our invention."

-Plato, The Republic

One of the most important questions in finance is how access to financial markets impacts real investment decisions. In addition to examining how financing affects investment levels, several theoretical and empirical papers suggest that access to public equity markets facilitates investment in riskier and more opaque projects. However, an appealing contrasting intuition, along the lines of Plato's proverb quoted above, would imply that a lack of access to external sources of financing might necessitate, rather than preclude, a more exploratory investment mix.

In this paper, we investigate how access to capital influences project choice. We use data from hydraulically fractured (*fracked*) wells in the North Dakota portion of the Bakken shale formation to distinguish riskier market-expanding projects from investments in proven markets. We find that private firms more intensely invest in the former type of projects, while public firms tilt more aggressively pursue the latter type. This stylized fact is often attributed to private firms exhibiting different managerial skills and preferences and benefiting from reduced agency frictions (Holmstrom (1989)). However, we posit that private firms' cost of capital disadvantages represent a material portion of the dynamics we observe. In our setting, entry into core markets is very costly. Furthermore, since high quality markets with little uncertainty support economies of scale, public firms can translate access to capital into cost advantages in those areas. We isolate the effects of access to capital via exogenous shocks to firm financing and within-firm changes in available capital and find strong support for our hypotheses.

The fracking revolution in North Dakota serves as a useful laboratory to examine how access to capital affects investments in new technologies for several reasons. First, the widespread adoption of fracking represents a highly disruptive technological advancement, as discussed in Blackwill and O'Sullivan (2014). Second, each of the over 11,000 fracked wells in our sample represents an investment of at least $5 million, and fracking investments across the United States together comprise one of the largest investment booms in modern history. These highly capital intensive projects require that most firms in our sample depend on external finance. Third, crude oil is a homogeneous commodity so competition on quality or price should not impact project choice. Finally, as we detail below, geographical variation in both shale quality and historical mineral rights of incumbent firms provide quasi-exogenous heterogeneity which helps us isolate the effects of firm financing on investment choice.

Our hand-parsed dataset of well surveys, filings, and reports from the North Dakota Industrial Commission (NDIC) allows us to observe detailed characteristics at the project level. Crucially, we use the geographic coordinates of each well head to distinguish between *frontier* wells, in which firms apply fracking techniques for the first time in new areas, and wells drilled in areas of known quality and with standardized fracking procedures. This data allows us to quantify the proportion of investments made by both public and private firms in more exploratory and risky projects. Using these metrics, we compare the mix of investments made by public and private firms in the cross-section and examine how firms adjust their investment mix in response to quasi-exogenous shocks to asset base values.

We first examine whether private firms tilt a greater share of investment towards fracking wells in new areas than do public firms. We define a *frontier* well as the first well in a previously unfracked oil field, as defined by the NDIC. *Frontier* wells have higher variation in initial crude oil production, and less follow-on activity relative to wells fracked in more established areas. These results corroborate prior studies suggesting that fracking in new areas entails large risks and results in material information spillovers.[1] Private firms' frontier share (the share of each firm's wells identified as *frontier*, within each quarter) is 3.6-5.1 percentage points higher than for public firms, which represents an economically significant difference versus the public firm average of 7.6%. Our tests control for two possible alternative explanations: 1) the fact that private companies in our sample frack fewer wells on average relative to public companies, and 2) the fact that private companies frack a greater share of wells earlier in the sample when more frontier drilling opportunities exist.

Differences in investment mix between public and private firms could derive from a multitude of factors. We employ two strategies to isolate and quantify the extent to which financial frictions contribute to the dynamics we discuss above. First, we exploit quasi-random variation in the values of assets held by incumbent firms prior to the fracking boom. We use non-fracked wells drilled before 2008 to proxy for firm mineral rights leases around the state. Since the mineral rights (*legacy leases*) for these wells were negotiated prior to the widespread use of fracking, the firms who hold legacy leases experience a positive shock to the value of their assets and their borrowing base. We show that each favorable legacy lease decreases private firms' investment tilt towards frontier activity by 0.63 percentage points. Moreover, we show this windfall effect is much stronger for private firms than for public firms, which suggests that the financing channel is an important determinant of the differences in investment mix that we observe. We also show that the effect of legacy leases on frontier activity cannot be explained by other factors linked to post-boom behavior, such as firm size, the ability to identify high-quality frontier assets, or capacity constraints.

To further confirm that access to financing drives differences in project choice, we examine

[1] Variation in subterranean rock characteristics across shale formations, such as North Dakota's Bakken, gives rise to risks resulting from variation in fracking efficacy, as discussed in Baihly et al. (2012), Jabbari, Zeng et al. (2012), and Saputelli et al. (2014).

within-firm changes in investment mix in response to variation in recent oil production, from recently drilled wells. Private firms are especially dependent on internal cash flows generated by oil producing wells and collateralized loans against proven oil reserves to fund new projects Azar (2017). We proxy for the capital available by aggregating the value of the oil production from each firm's fracked wells over the most recent 3 years. We find that in response to a $1 million change in available capital, private firms reduce their investment mix tilt towards frontier areas by 1.4 percentage points, or 11% relative to the private firm average. Consistent with our findings in reaction to legacy lease endowments, the sensitivity of investment choice to recent production is stronger for private than for public firms. We argue that these findings show how private firms rely on reserves collateral for financing to a much higher degree than do public firms, and that these differences in access to external financing have significant implications for project choice. Also, our within-firm results suggest differences in investment patterns between public and private firms are not purely the result of time-invariant characteristics that affect both investment and listing choice.

Finally, we present evidence that greater access to capital provides public firms an additional advantage via economies of scale in developed areas. Specifically, we show that public companies, and better financed private firms, tilt investment towards *pads*, which are large-scale projects in which firms drill and frack multiple wells in rapid succession in very close proximity. Since pad drilling can yield material cost savings of hundreds of thousands of dollars per well, the emphasis on scale-improving pad wells is a major benefit for operating in established markets with lower productivity uncertainty. Furthermore, the economics of these projects helps account for the disparity in the *levels* of investment between private and public firms.[2]

[2]Public companies drill and frack over 80% of the wells in our sample. See the following Energy Information Agency article for information on cost savings from pad drilling: https://tinyurl.com/y9q2t638.

Our paper relates to the literature examining firm financing and investment such as Fazzari, Hubbard, and Petersen (1988), and to more recent papers comparing how public and private companies invest. For example, Sheen (2016), finds that private petrochemical firms invest differently, and more efficiently, than public firms. In addition, Asker, Farre-Mensa, and Ljungqvist (2014) finds that public firms investments are less responsive to changes in investment opportunities than private firms. In addition, Almeida et al. (2017) finds that less financial slack mitigates agency frictions and leads to more efficient generation of innovation (although they consider only public firms). Our findings affirm that private firms invest differently than do public firms, and that lack of access to financing can foster more a more innovative investment mix. However, we focus on differential access to finance rather than agency frictions in explaining our results.

Another closely related paper is Gilje and Taillard (2017), which uses natural gas wells to demonstrate that access to capital allows public firms to respond more quickly to new investment opportunities. Their results are consistent with our finding that public firms invest more heavily in larger scale-building projects. However, we focus more on how firm financing relates to investment composition, rather than how firms respond to opportunities in overall investment levels. Moreover, we exploit shocks to firm financing, not investment opportunities, and focus the exploratory investments of private firms.

Finally, our paper also relates to the literature which examine R&D and patents to compares how public and private firms innovate as surveyed by Hall and Lerner (2010) and Kerr and Nanda (2015). For example, Acharya and Xu (2017) finds that public firms in external finance dependent industries spend more on R&D and generate better patents than private firms. In contrast, Bernstein (2015) shows that the quality of internal innovation declines following IPOs, but that public firms acquire external innovation. Rather than use patents, we characterize the tilt of each company's investment mix towards more speculative projects.[3] Nonetheless, our findings are somewhat supportive of Bernstein (2015) in that we find private companies more aggressively speculate with their investment tilt.

1. The Fracking Boom in North Dakota

The fracking revolution in North Dakota, and the widespread adoption and implementation of fracking generally, represents a highly disruptive technological advancement, as discussed in Blackwill and O'Sullivan (2014). Energy firms in North Dakota first began adapting fracking to oil drilling in the early/mid-2000's, as we show in Appendix Figure A1. Healy (2012) succinctly defines fracking as follows:

> Hydraulic fracturing, or 'fracking', is a method used by drilling engineers to stimulate or improve fluid flow from rocks in the subsurface. In brief, the technique involves pumping a water-rich fluid into a borehole until the fluid pressure at depth causes the rock to fracture. The pumped fluid contains small particles known as proppant (often quartz-rich sand) which serve to prop open the fractures.

Engineers performed the first frack in Kansas in 1949, as discussed in Montgomery, Smith et al. (2010). While initially used to stimulate the production of natural gas, fracking has been subsequently adapted for crude oil production. In this paper, we study the adoption of fracking in crude oil production because there exists detailed well-level data for oil wells and because the market for crude oil is very large and global in scale. By contrast, natural gas is far harder than crude oil to transport, and is less widely used.

[3]We do not examine R&D or patents as R&D expenses are minimal for energy firms, and patents are rarely used to protect innovations in the energy industry, as shown in Cohen, Nelson, and Walsh (2000).

Private firms were the first to frack in North Dakota, and anecdotal evidence suggests that they are also more likely to push the boundaries of the technology. The first frack to occur in our data was executed by a small private North Dakota based company called Nance Petroleum during the winter of 2000.[4] That first frack involved pumping 147,000 pounds of proppant into a well reaching almost two miles below the surface, and extending three-quarters of a mile horizontally. Over the next three years three, more fracks occurred in North Dakota, each performed by a private company. Figure 1 displays the time-series of North Dakota fracks. The top panel shows that in the early part of the sample (2000-2007), private firms comprise a far larger share (107 out of 303) of these early fracked wells. While public companies entered and dramatically increased fracking activity relative to private companies - publics comprise 82% of the massive boom in fracks that occurred in North Dakota between 2008-2016 - private firms remained focused on expanding the geographical frontier of Bakken shale formation. The exploration of the frontier areas by private operators has been recognized by the trade press, such as Platt's (see for example: https://tinyurl.com/y9etso2d), which are summarized by the remarks of Justin Kringstad, director of the North Dakota Pipeline Authority:

> "What we would've considered a fringe area a year ago are now considered economic territory in the state of North Dakota." ... Relatively smaller operators, either unable or unwilling to acquire so-called Tier 1 acreage in the core of the core, are looking at less costly Tier 2 and even Tier 3 areas and considering adding rigs on the outskirts of the Bakken's most prolific plays.

Fracking oil wells in North Dakota involves significant costs. First, fleets of specialized

[4] Nance has since been acquired by St. Mary Land & Exploration Company, which is now SM Energy: a public company with a $2.4 billion market cap.

pumping trucks pump over 150,000 barrels of frack fluids into wells at pressures exceeding 9,000 pounds per square inch (psi). These materials and equipment must be purchased or rented. In addition, in order to be fracked, wells must be drilled deep enough to reach the Bakken shale rock formation which is generally at least two miles below ground. Finally, fracked wells must also extend horizontally, within the cross-section of the shale, for another one or two miles. Drilling deeply, and then turning horizontally, requires highly technical directional drilling equipment. These factors can double or triple the cost of a fracked well relative to that of a non-fracked well. However, as we show in Appendix Figure A2, fracked wells produce oil at far higher rates than non-fracked wells on average, which generally justifies these costs.

The gains in oil production, relative to the added costs, resulted in a boom in oil fracking investment primarily in shale formations below North Dakota and Texas starting in 2008. According to the U.S. Energy Information Agency (EIA), drilling fracking and leasing costs in North Dakota average between $7-10 million per well.[5] Our sample consists of 11,313 wells, which implies an aggregate capital investment of more than $80 billion, the bulk of which occurs between 2010 and 2015. This does not capture investments in pipelines, processing plants, terminals, and other infrastructure necessary for getting the oil from North Dakota to refineries in the U.S. Mid-Continent and Gulf Coast regions. EIA data indicates that fracking activity in Texas is roughly three-fold higher than in North Dakota, which suggests that the overall fracking boom rivaled (or possibly exceeded) the telecom boom of the late 1990's in terms of aggregate dollars invested, according to Doms (2004).

The drilling and fracking boom in North Dakota over the past decade, compounded by increases in oil production per well, contributed to dramatic increases in crude oil production

[5] See the EIA's "Trends in U.S. Oil and Natural Gas Upstream Costs": https://tinyurl.com/zh4kdvx.

in North Dakota and in the U.S., which we show in Appendix Figure A3. Between 2000-2016, the years spanned by our sample, North Dakota's aggregate oil production grew more than 10-fold: from less than 100,000 barrels per day to over 1 million barrels per day. During this time North Dakota went from accounting for from less than 1% of total U.S. crude oil production to over 12%. Currently, North Dakota is the second largest oil producing state (behind Texas). According to the EIA, oil flowing from fracked wells accounts for over half of aggregate U.S. production as of 2016, and accounted for the entirety of the crude oil production growth over the past decade.[6]

The recent growth in U.S. crude oil production has disrupted import/export dynamics and lowered global energy prices. Between 2008-2016 total U.S. crude oil imports fell 20%, and U.S. imports from OPEC countries fell 40%. These declines are remarkable considering that U.S. GDP expanded by 24% over the same period (according to the World Bank). Crude oil prices in recent years are dramatically lower than in the years prior to the 2010-2015 fracking boom. Outside of the U.S. many sources of energy, such as liquefied natural gas (LNG), are indexed to crude oil prices. Therefore, fracking in the U.S. has contributed to lower energy prices throughout the world. These developments have significant implications for the global economy and global geopolitics, as discussed in Blackwill and O'Sullivan (2014).

2. Data

2.1. Well-level Characteristics

We assemble data for 11,313 unique oil wells from the North Dakota Industrial Commission (NDIC) for our analysis, which is similar to the data used in Covert (2015). Each of the wells in our sample is an oil well, which is drilled into the Bakken shale formation, and is

[6] See the EIA's "Today In Energy" on March 15th, 2016: https://tinyurl.com/y9fdb4no.

completed using hydraulic fracturing (fracking). We define individual wells using subscript i, define the firm which drills and fracks each wells using j, define the quarter in which the construction of the fracked wells begins using t, and define the geographic area of the surface of each the fracked well using g.

Our sample of wells is drilled and fracked by 98 unique energy firms. We hand match firm names from the NDIC data to energy firm names from The Center for Research in Security Prices (CRSP) to define which firms are publicly traded and which firms are privately held. We research each of the 98 companies to ensure we capture names in the NDIC data which relate to operating subsidiaries of public companies. We define *private* to be firms not matched to CRSP. In the sample, we identify 38 public and 60 private firms, and, as we show in Table 1, 17% of the wells in our sample were drilled and fracked by private companies.

Our data include a rich set of characteristics for each fracked well. First, we measure productivity as $Oil\,Production_i$, which is the number of barrels of crude oil from well i over the first 24-hours that the well produces.[7] Second, we know the total depth of each well ($Total\,Depth_i$), the total distance that each well extends laterally ($HDepth_i$), and the vertical depth ($VDepth_i$), which we calculate as: $Total\,Depth_i - HDepth_i$.[8] Third, we tally the number of well bores which connect to each wellhead ($Laterals_i$). Finally, we also observe the number number of days that the drilling rig is on site to drill each well ($Drill\,Days_i$). As we show in Table 1: our average fracked well is 3.75 miles deep, requires 32 rig-days to drill, and produces 1,100 barrels of oil on the well's first day.

The NDIC requires detailed plans describing the drilling and fracking techniques for each well be filed and made public. This information, as shown in Covert (2015), can be a

[7] Fracking is especially effective in increasing a well's *initial* production, as discussed in the EIA's "Initial production rates in tight oil formations continue to rise": https://tinyurl.com/yatk5ed8.

[8] the EIA's "Trends in U.S. Oil and Natural Gas Upstream Costs": https://tinyurl.com/zh4kdvx indicates that costs are positively correlated with each fracked well's depth.

source of learning for competitors. However, the NDIC allows firms to request confidential treatment, which embargoes the well data for a 6-month period. After this period, the data is revealed to the public, and we can observe if the well data was protected by confidential treatment ($Confidential_j$). This information embargo would dampen information spillovers to competitors such as which areas are productive new processes are most effective.[9] Roughly 20% of all wells in our sample involve confidential treatment, and we use this data to examine competitive dynamics and information signaling.

2.2. Fracking Wells in Frontier Areas

We use the geographic location of each fracked well's wellhead to define several variables which classify whether the well is drilled in a new or developed area. This is the primary way we characterize a firm's investment composition. We define the binary variable $Frontier\,Field_i$ which indicates the first fracked well in a given oil field (oil fields are defined by the NDIC). We show an example oil field called *Twin Valley* which is outlined in red in Appendix Figure A4. Twin Valley covers an 8-square miles area, as indicated by the black square-mile grid-squares, and the wellheads of the various fracked wells appear as black dots. In Appendix Figure A5 we show new $Frontier\,Field_i$ fracks (red dots) relative to previously fracked wells (black dots) and new wells fracked in established areas (blue dots), that occur during 2006, 2008, 2010, and 2012. These maps show how rapidly firms develop and drill the Bakken shale, and how the *frontier* shifts outwards as previously developed areas become crowded.

We also use our geographic data to define well remoteness directly: $Remote\,Distance_i$ is the distance (in miles) of each fracked well i to the nearest fracked well that exists in the data prior to when construction of well i was at time t, and $Remote\,oDistance_i$ as the

[9] This effect is discussed in trade press, such as: https://tinyurl.com/ybxbu5rf.

distance to the nearest fracked well constructed by the same firm prior to well i at time t. As we show in Table 1: on average, when a well is fracked, it is 0.57 miles from the nearest existing fracked well. In addition, over the course of the sample, 3% of wells are drilled in frontier oil fields.

Fracking previously unexplored and more remote areas presents significant technical challenges, and firms applying fracking techniques in new areas face a higher degree of risk. Even for wells drilled into the same shale formation, sub-surface geologic characteristics can vary dramatically from area to area. As such, successfully fracking new locations is more complex and risky than repeatedly fracking in a more well-known area. We present several analyses to illustrate this fact. First, we present a variance decomposition of $Oil\,Production_{i,j}$ for our sample of fracked wells in Appendix Table A2, which shows that geography accounts for an outsized share of the overall variation in well productivity.

Second, we illustrate the particularly high-risk nature of more remote frontier-expanding wells in Figure 2. In the first panel, we show that the initial production from wells drilled in new fields is 28% below the cross-sectional average, and these new wells also have a very high degree in variation of their initial production. As subsequent wells are drilled and fracked, production increases and the variation in production decreases. We attribute these improvements to knowledge gains and process improvements as energy firms adapt fracking technology to the geographic-specific challenges presented by each new area (see also Covert (2015)).

In the second panel of Figure 2 we show the average number of subsequent wells, drilled and fracked in the same field within one year, conditional on the sequence of wells previously drilled in each field. In many fields, no subsequent wells will ever be drilled after the first, exploratory, well. However, for fields in which second, third, fourth etc. wells are drilled the likelihood that fifth, sixth, etc. even a fiftieth well will be drilled increases. The probability of subsequent wells is lowest for the first well in a field, which represents an additional aspect of risk for wells drilled in previously unexplored areas. Given the risks of experimenting with these new technologies to unknown rocks for the first time, and the information externalities that pioneering companies provide to the rest of the industry, we consider fracking in new fields our primary measure of exploratory investment.

In our regression specifications, we aggregate the frontier and remoteness measures at the firm-quarter level to facilitate comparison between firms. We define $Frontier\,Field\,Share_{j,t}$ as the number of $Frontier\,Field$ fracked wells that firm j fracks during quarter t divided by the total number of fracked wells that firm j fracks during that quarter. As we show in Table 1 on average $Frontier\,Field_i$ fracks represent 10% of firm's overall fracked well mix, which exceeds the share of overall wells drilled (3%) by over three-fold. This reflects the fact that $Frontier\,Field\,Share_{j,t}$ averages across companies/quarters, and reflects a skew driven by a greater number of smaller companies tilting their fracks towards frontier areas, as we discuss in more detail in Section 3.1 below.

Finally, we define two variables which describe the order and timing in which firm's drill and frack wells within each oil field, g. These variables help us examine whether public firm entry into new fields lags those of private firms. We define $Delay\,Time_{j,g}$ as the difference between firm j's first fracked well in oil field g (its *entry well*) and the date of the oil field's $Frontier\,Field_g$ fracked well. Similarly, we define $Delay\,Well_{j,g}$ as the number of wells that had been drilled in oil field g prior to firm j's entry well.

2.3. Pad Drilled Wells

The second type of investment we can identify in our sample are wells drilled on the same pad. Prior to the widespread adoption of fracking, energy firms would generally drill wells that were widely spaced geographically which would require that the firm disassemble move reassemble the drilling rig for each well. Fracking allows for wells to be drilled much closer together, and pioneering firms began to use one rig to drill multiple wells from a single surface location – *pad* drilling. This saves time and money, and is less environmentally disruptive.[10]

Pad drilling cannot be directly observed in the data, but we infer pad drilling patterns following industry standards (e.g. `https://tinyurl.com/yaj6epts`) and identify pad wells as any cluster of wells that is drilled sequentially by the same firm-rig pair and within 0.1 miles. Our primary measure of pads includes all qualifying clusters of two or more wells (denoted as Pad).[11]. We choose this threshold because it generates a time-series of pad drilling that resembles estimates consistent with the statistics on pad drilling generated by DrillingInfo, a premier analytics firm for the E&P industry. However, we also ensure our results are robust to larger cluster size thresholds. The map in Appendix Figure A4 illustrates several pad wells, which appear as tight clusters of black circles (wellheads) in which several lines (horizontal wellbores) extend. As we show in Table 1 58% of our sample of fracked wells are drilled in pads.

Similar to our frontier measures above, we aggregate the above pad well data at the firm level, and at quarterly frequency, to create proxies for the degree to which the mix of each firm's fracked wells tilts towards large pad well projects. We define $Pad\,Share_{j,t}$ as the number of $Pad_{i,j}$ fracked wells that firm j fracks during quarter t divided by the total number of fracked wells that firm j fracks during quarter t. As we show in Table 1, the sample average for $Pad\,Share_{j,t}$ of 39% is far lower than the overall share of wells drilled in pads (58%) reflecting the fact that a greater number of smaller firms drill a lower share of

[10]See the EIA's "Today in Energy" September, 2012 for a discussion of pads: `https://tinyurl.com/yavnbkoc`.

[11]We display the time-series of the share of wells denoted as $Pad_{i,j}$ in Figure 3

wells in pads, which we discuss in Section 3.3 below.

2.4. Energy Firm Capital Access

The energy industry is immensely capital intensive, and many firms rely heavily on external financing for their investments (Gilje and Taillard, 2017). Firms typically use their mineral rights and oil reserves as collateral to secure loan financing. Thus, the quality of a firm's mineral rights and the amount of proven reserves largely determine the firm's available credit.

In our extended sample, we observe all wells drilled in North Dakota, including non-fracked wells. Specifically, we observe the universe of *legacy* - i.e. non-fracked and non-Bakken - wells that each firm drilled prior to the fracking boom. We classify 2008-on as the post-boom years, and define the variable $Good\,Lease_j$ as the number of legacy wells a firms operates prior to 2008 that are within 1 mile of at least 10 post-boom fracked wells. After the fracking boom, firms with *good leases* have greater credit access since their mineral rights are more valuable as collateral. We exploit the distribution of $Good\,Lease_j$ across private and public firms as a source of exogenous variation in financing conditions.

Additionally, based on conversations with current and former energy executives, many firms, especially private firms, depend on reserve-based lending as an important source of funds for investing in fracking. Therefore, we proxy for a firm's collateralizable reserves, $Recent\,Productivity_{j,t}$, using the trailing three-year total number of wells drilled, multiplied by the average $Oil\,Production_{i,j}$ for each well, multiplied by the oil price (1-month NYMEX future) from the prior quarter. This is a proxy for the value of capital available to the firm j at quarter t.

3. Results

3.1. Frontier Drilling

In this section we examine how access to external sources of financing relates to a firm's propensity to invest in new, risky, frontier-expanding areas. For our first set of tests we run pooled OLS regressions, with year fixed-effects, as outlined in Equation (1) below. We include year fixed effects in order to control for time-specific factors, such as the oil price, which affect firm's financing conditions, and to adjust for the time-trends in drilling and fracking activity over the time-series, as we show in Appendix Figure A1 and Figure 1. The dependent variable in this regression specification is $Frontier\,Field\,Share_{j,t}$, which is our proxy for each firm's investment tilt towards fracking wells in new areas. We report the results of running the regression outlined in Equation (1) in Table 2:

$$Frontier\,Share_{j,t} = \beta Private_j + \gamma_{year} + \epsilon_{j,t}. \tag{1}$$

The positive and significant coefficient for $Private_j$ in Columns (1) and (2) of Table 2 indicates that on average private firms share of fracked wells are between 3.64 -5.10 percentage-points higher than for public firms. As we show in Table 1, the unconditional average for $Frontier\,Field\,Share_{j,t}$ is 10%, which indicates that private firms share of fracked wells is more than 50% higher than for public firms, which we believe reflects an economically significant difference in investment policies between public and private firms.[12]

In Columns (3) and (4) of Table 2 we show the results from running the regression outlined in Equation (1) using $Remote\,Distance_{j,t}$, our alternative proxy for each firm's average fracked well remoteness, as the dependent variable. The positive and significant

[12] We cluster errors by firm (j) throughout to adjust for within-firm correlations in investment patterns. Our results are robust to a myriad of alternative error clustering specifications.

coefficients for $Private_j$ indicate that on average, wells fracked by private firms are located between 0.36-0.61 miles further from any other wells relative to wells fracked by public firms. This represents an economically significant magnitude relative to the sample average for $Remote\,Distance_{j,t}$ of 0.57 miles. These results support those presented above, and suggest that the mix of investments is quite different between private and public firms.[13]

The differences in $Frontier\,Field\,Share_{j,t}$ we show above may arise, in part, due to the fact that public firms drill many more wells than private firms on average. To ensure that our findings are not driven by disparities in levels of investments, we also examine the timing of entry into new areas. For this analysis we use a sub-sample which includes only the first well, drilled and fracked by each firm j, in each field g. We use variables to measure the time ($Delay\,Entry_{j,g}$), sequence ($Delay\,Well_{j,g}$), and distance ($Remote\,Distance_{j,g}$ and $Remote\,oDistance_{j,g}$) of each firm j's entry into field g relative to the first well in each field. As we show in Figure 2, uncertainty regarding field quality drops drastically as as more wells are drilled and fracked. For our field entry regressions we include two sets of fixed effects. We include year fixed effects to address the overall variation in activity, and a fixed effect for each firm's overall first well to address the fact that each firm's initial entry in the data tends to be more remote than subsequent fracked wells. We show the general outline of these regressions in Equation (2) and present the results in Table 3:

$$Delay\,Entry_{j,g} = \beta Private_j + \gamma_{year} + \eta_{entry} + \epsilon_{j,t}. \tag{2}$$

The negative and significant coefficient for $Private_j$ in Column (1) of Table 3 indicates that private firms enter oil fields 228 days earlier than public companies on average.

[13] For additional robustness, we present the result from a regression similar to Equation 1 but for the dis-aggregated sample of 11,313 in Appendix Table A3.

In Column (2) of Table 3 we show regressions similar to Equation (2) but with the dependent variable $Delay\,Well_{j,g}$, which indicates the number of fracked wells that have occurred since the first frontier well in each field. The negative and significant coefficient in Column (2) indicates that private firms enter fields about four wells before public firms on average, which supports the results above which show that public firms enter later and tilt investments towards more mature fields.

In Columns (3) and (4) of Table 3, we compare the "remoteness" of public and private firm's entry wells. Using $Remote\,Distance_{j,g}$ and $Remote\,oDistance_{j,g}$ as dependent variables, we re-estimate the regression outlined in Equation (2). The positive coefficient in Column (3) indicates that, on average, private firms place their entry wells about 1 mile further away from existing wells relative to public firms. In Column (4) we show that private firms drill wells 3.5 miles further away to their own wells when entering fields. These results support our findings above, and suggest that private firms more aggressively tilt their investments towards the more remote frontier areas.

3.2. The Role of Firm Financing

We believe that a significant portion of the differences in the investment mix between private and public firms is attributable to differences in access to financing. However, we acknowledge that private and public firms differ across many other pertinent dimensions that might contribute to the results in Tables 2 and 3. For example, public firms are more vulnerable to agency frictions (Stein (1989)) which may hamper their ability to engage in more risky and opaque projects like frontier drilling. Furthermore, it is possible project selection dictates listing choice and managers who prefer to invest more in frontier projects choose to remain private for disclosure requirements (Bhattacharya and Ritter (1983), Farre-Mensa (2017)) or due to the high fixed costs of IPOs (Ritter (1987)).

3.2.1 Legacy Leases and Access to Capital

To isolate the effects of capital access on project choice we exploit quasi-random variation in "legacy" mineral right leases as an exogenous shock to the ability of firms to access external financing. We observe the universe of legacy wells, which were drilled in shallower formations above the Bakken prior to the adoption of fracking, that each firm owned prior to the onset of the fracking boom. We assume that mineral rights attached to legacy wells were negotiated without consideration of then-unknown technologies, such as fracking, which would allow for economic exploitation of oil from far deeper and more challenging geological formations such as the Bakken. However, since legacy wells cover the geographic footprint of the (far deeper) Bakken formation as well, firms lucky enough to hold legacy leases in the right areas exhibit a sharp, exogenous appreciation of their asset base in the years following the start of the fracking boom (roughly 2008, as we show in Figure 3). We argue that this shock facilitates firm financing both by endowing firms with assets that may otherwise be prohibitively expensive, and by increasing the value of their collateral base. Importantly, since private companies are more reliant on loans collateralized by reserves (Azar (2017)) than their public counterparts, we hypothesize that good legacy leases should affect the level and mix of investments more dramatically for privately held firms.

Based on the time-series of drilling rates in Figure 3, we define the period after 2008 as the post-fracking-boom. We then define the variable $Good\,Lease_j$ as the number of legacy wells a firms operates in 2007, the last pre-boom year, that are within one mile of at least 10 future fracked wells.[14] The logic behind this definition of $Good\,Lease_j$ is that firms own mineral rights in the immediate vicinity of their wells (see Covert (2015)) and that the most favorable shale areas will be heavily populated with fracked wells. We include in our

[14] In Appendix Table A5 we show that our results are robust to various definitions of $Good\,Lease_j$.

analysis only firms who operate legacy assets in the pre-boom years (incumbent firms). We then estimate the following regressions for the post-boom years, which we report the results in Table 4:

$$Frontier\,Share_{j,t}{=}\beta_1 Private_j + \beta_2 Good\,Lease_j + \beta_3 Private_j \times Good\,Lease_j + \epsilon_{j,t} \quad (3)$$

$$(4)$$

The insignificant coefficient for (β_2) in Column (1) of Table 4 indicates that good legacy leases have a minimal effect on public firm's investment in frontier areas. In contrast, the negative and significant coefficient for the interaction term, β_3, indicates that each additional good legacy lease significantly reduces investment in frontier areas by private firms. The sum of β_2 and β_3 suggests that each legacy lease reduces the proportion of frontier investments by 0.64 percentage points for private firms, which suggests that a private firm with five good leases would have an investment mix equivalent to the average public firm.[15] In Columns (3) and (4) of Table 4 we show that these results hold using our alternative measure of project remoteness, $Remote\,Distance_{j,t}$, as the dependent variable.

Our analysis of legacy lease endowments assumes that the distribution of favorable legacy leases is independent of other factors that dictate post-2008 investment patterns. To validate this assumption we control for total legacy leases, with the variable All Lease$_j$, which we show in Column (2) and (4) of Table 4. Adding this control ensures that our results are not driven by a correlation between $Good\,Lease_j$ and firm size, and does not materially affect our findings.

In addition, we conduct a placebo test to rule out the possibility that firms with high-

[15] The average $Frontier\,Field_j$ for private firms in the incumbent firm sample is 3.33 percentage points higher than for public firms after 2008.

quality legacy assets are different in some way other than access to capital, and that this difference drives our observed results. Specifically, we define a $Placebo\,Good\,Lease_j$ by examining the number of legacy wells that do not meet the criteria for $Good\,Lease$, but are located within a mile of at least ten other non-fracked wells. Firms whose legacy assets are located in favorable non-shale locations should not experience any asset appreciation in the post-boom period and should therefore not exhibit any change in post-boom investment patterns. To verify this intuition, we re-estimate Equation (3) using our placebo definition of $Good\,Lease_j$ and report the results in Table 5. The placebo effect, captured by β_3, is economically small and for the most part statistically insignificant, suggesting it is not some unobserved characteristic associated with the ownership of high-quality assets that drives our results.[16]

We also attempt to rule out that the $Good\,Lease_j$ shock affects firm behavior by a mechanism other than improved access to financing. First, we ask whether our results could obtain due to capacity constraints. If private firms are constrained in the amount of projects they can pursue at a time, they may choose to prioritize developing their assets in place rather than pursuing new projects even absent any financial frictions. This dynamic may result in private firms tilting investment to nearby (i.e. non-Frontier) areas, due to greater capacity constraints, rather than due to great access to external sources of financing.

To address capacity constraints as a mechanism, we examine whether private firms with good legacy lease endowments invest differently even in areas not connected with the development of the legacy assets. If good legacy leases affect private firm behavior only due to capacity constraints, we should not find a material effect when examining this sub-sample.

[16] While tiny in magnitude, the interaction term in Column (4) of Table 5 is statistically significant at the 10% level. This result may be due to the fact that ownership of high-quality shale and non-shale legacy assets is somewhat correlated. Untabulated results, including both the genuine and placebo definitions of $Good\,Lease_j$ render the placebo effect insignificant.

To implement the test, we re-estimate Equation (3) after excluding wells within the vicinity (i.e. 1 mile) of a firms' legacy leases and report the results in Table 6. We find qualitatively and quantitatively similar results after excluding all wells connected with the legacy lease. The coefficient on the interaction term remains statistically significant and is of a similar magnitude to the baseline results in Table 4 across all specifications. These findings confirm that capacity constraints are not a material concern.

We also assess whether the $Good\,Lease_j$ results in Table 4 obtains due to differential levels of expertise in detecting high-quality frontier assets between private and public firms. If private firms are worse at predicting high output areas compared to public firms, then those private firms endowed with $Good\,Lease_j$ assets may stick to drilling in that area not because of an increase in access to financing but because their likelihood of success elsewhere is low. Alternatively, private firms may have an advantage in forecasting frontier profitability. However, if this advantage exists, then increasing financial access should not dampen their investments in frontier activity.

To test for differential rates of expertise, we look at the probability that a field is more likely to *boom* (succeed) or *bust* (fail) depends on whether it was first fracked by a private of public firm. We define *Boom* is an indicator equal to 1 if the number of wells drilled in this field is in the top quartile compared to other fields drilled in the same year, *Bust* is an indicator equal to 1 if the number of wells drilled in this field is in the bottom quartile compared to other fields drilled in the same year, and $Private_g$ is an indicator equal to 1 if the field was first fracked by a private firm. We include year fixed effects in order to control for time-specific factors. Specifically, we run the following regression:

$$Boom(Bust)_g = \beta Private_g + \gamma_{year} + \epsilon_{j,t}. \tag{5}$$

The coefficient for $Private_g$ in Columns (1) and (2) of Table 7 indicates there is no significant difference between fields first fracked by private firms and those first fracked by private firms in the propensity to become a booming field. Public fields are slightly, though insignificantly so, better, which can be explained by public firms having more money to buy better mineral rights. Furthermore, the coefficient for $Private_g$ in Columns (3) and (4) of Table 7 indicates there is no significant difference between fields first fracked by private firms and those first fracked by private firms in the propensity to become a bust. As these (null) results point to no material (dis)advantages of private firm in frontier scouting ability, they indicate that the $Good\,Lease_j$ results cannot obtain via that channel. Overall, our tests suggest that $Good\,Lease_j$ serves as an exogenous shock to private firm financing conditions, and that private firms endowed with more $Good\,Lease_j$ assets invest in a manner that more closely resembles the investment mixes of public firms.

3.2.2 Recent Productivity and Capital Availability

Another way to isolate the effects of capital access on project choice is to look at the productivity firm wells. We use the variable $Recent\,Productivity_{j,t}$ to proxy for a firm's available capital, which includes cash generated by selling crude oil and banks loans that use proved oil reserves as collateral. We run regressions similar to the regression outlined in Equation (6) in Table 8:

$$\begin{aligned} Frontier\,Share_{j,t} = &\beta_1 Private_j + \beta_2 Recent\,Productivity_{j,t} \\ &+ \beta_3 Private_j \times Recent\,Productivity_{j,t} + \epsilon_{j,t}. \end{aligned} \tag{6}$$

The negative and significant coefficient for the interaction term, β_3, in Column (2) of Table 8 indicates that greater $Recent\,Productivity_{j,t}$ significantly reduces the tilt in investment towards frontier areas for private firms in the cross-section. This result supports our findings in Table 4 which also indicate shocks to asset values, for private firms, lowers the mix of investment in frontier projects.

In Column (3) of Table 8 we present a similar regression, but include firm fixed effects. The negative and significant coefficient for β_2 indicates that higher recent productivity, which should correlate with an increase in firm's asset bases, negatively correlates with firm's investment tilt towards the frontier. The negative and significant coefficient for the interaction term, β_3, indicates that this effect is significantly more pronounced for private firms. We interpret this as additional evidence that, within-firm, greater access to financing result in a lower mix of investment towards frontier projects.

In Columns (4) and (5) of Table 8 we show that the results we show in Columns (2) and (3) respectively are robust to using our alternative measure of project remoteness, $Remote\,Distance_{j,t}$, as the dependent variable. Specifically, the regression in Column (5) shows that, within-firm, increases in recent productivity negatively correlate with fracked well remoteness. In addition, these effects are especially pronounced for private firms.

3.3. Economies of Scale and Project Choice

Our findings thus far indicate that adverse financing conditions lead private firms to tilt their investment mix towards more risky frontier projects. Our next set of tests show that better access to capital provides firms this access an additional advantage via economies of scale. Specifically, we examine the effect of access to financing on the investment tilt towards multi-well pad drilling and fracking, which is the practice of drilling and fracking multiple wells from a single surface location.

Pad drilling saves time and money through several different channels. Firstly, pad drilling cuts down on rig assembly and relocation times since rigs don't have to be disassembled and moved several miles to new drill sites. Additionally, pad drilling allows contractors to maximize fluids that assist vertical drilling as one batch, then switch to fluids that assist horizontal drilling without having to clean or remix multiple times. Finally, consolidating drilling sites saves on infrastructure investment such as water, power, and road construction.

To illustrate the efficiency gains from pad drilling, we compare the time it takes to drill wells in pads relative to drilling one-off wells. We measure efficiency via our variable $Drill\ Days_{i,j}$, the number of days between when drilling began for the well i and when total well depth was reached. Our main variable of interest is $Pad_{i,j}$, which is an indicator that the well i is part of a pad. To compare pad and non-pad wells we estimate the regression outlined in Equation (7), and include a vector of controls $X_{i,j}$ and a vector of fixed effects γ which we discuss below:

$$Drill\ Days_{i,j} = \beta_1 Pad_{i,j} + \beta_2' X_{i,j} + \gamma + \epsilon_{i,j} \tag{7}$$

We present the results of the analysis in Table 9. The negative and significant coefficient for $Pad_{i,j}$ in Column (1) indicates that wells drilled in pads take 6.5 fewer days to drill relative to one-off non-pad wells. The intercept terms indicates the average non-pad well takes slightly more than one month to drill, which suggests that the time savings for pad drilling, almost one week, is highly economically significant.

In Column (2) we show that this result is robust to including controls which proxy for the intensity of the drilling for each well, including the well's depth. While well depth and laterals significantly increases the drilling time for wells, including these controls does not alter the point estimate for $Pad_{i,j}$ relative to Column (1). Our most conservative specification, which includes fixed-effects for year, firm, geographic area (field), and rig, indicates that pad drilling saves on the order of about 1.7 days (Column (3)) or about 7% (Column (4)) of total drilling times. This estimate is on par with survey-based findings that pad drilling saves about 10% on drilling costs (e.g. https://tinyurl.com/y9aa4brs).[17]

While pad drilling creates savings on a per-well basis, these multi-well projects require significant upfront investment, and ex-ante commitments, relative to one-off well projects. Ex-ante commitment are not suitable for frontier wells, where quality of the shale and the right technology mix are unknown. This logic, combined with our findings above, would suggest that public firms, who can more easily marshal resources to capitalize large-scale pad drilling sites, should employ pad drilling in better known areas. By contrast, private firms are likely at a significant disadvantage with regard to drilling in developed fields, due to greater constraints on access to external financing, and will therefore pursue frontier projects. We verify this intuition by re-estimating Equation (1) replacing the dependent variable with $Pad\,Share_{j,t}$ and report the results in Table 10. The negative and significant coefficient for $Private_j$ in Columns (1) and (2) indicate that private pad shares are on average between 14.6-21.1 percentage points lower than public firm pad shares. As the average public firm pad share stands at 47.2 percentage points (intercept of Column (1) in Table 10), these discrepancies are economically significant as well.

To connect the differences in pad shares to financial capacity we also re-estimate Equation (3) with $Pad\,Share_{j,t}$ as the dependent variable. We report the effects of $Good\,Lease_j$ on pad shares in Columns (3) and (4) of Table 10. Our estimates indicate that each additional $Good\,Lease$ increases private firm pad shares by 1.5-2.4 percentage points ($\beta_2+\beta_3$), a quantity that is both statistically and economically larger than the effect of $Good\,Lease_j$ for public firms (β_2 only). Likewise, the estimates in Columns (5) and (6) of Table 10 indicate that a one million dollar increase in $Recent\,Productivity_{j,t}$ increases pad shares for private firms

[17]Note that this is a conservative estimate of cost savings since it does not include time savings from not having to disassemble and relocate the rig, nor does it account for the infrastructure savings.

by 1.2-5.1 percentage points. All together the findings presented in Table 10 suggest that a material portion of the difference in pad utilization rates between private and public firms derives from access to external capital. The use of pad drilling, which is most effective in oil fields with proven quality and standardized fracking technology, is another channel by which access to capital informs the project choice of private and public firms.

3.4. Disclosure Requirements

We perform one additional test to rule out a specific manifestation of reverse causality. Specifically, we assess whether disclosure requirements lead firms engaged in frontier investment to remain private. To test this hypothesis, we re-estimate Equation 1 using $Confidential_{i,j}$ as the dependent variable. We report the results in Table A6. The coefficient on $Private_j$ is negative, albeit statistically insignificantly so, suggesting that if anything, private firms are less likely to petition for confidential status.[18] Importantly, in Column (3) of Table A6 we verify that privates are no more secretive regarding their frontier wells. This finding helps reject the notion that frontier drillers remain private due to disclosure reasons.

4. Conclusion

We use detailed micro-data on oil well drilling in North Dakota to examine differences in investment choices between private and public firms. Rather than focus on the *level* of investment, we analyze whether private and public firms engage in different *types* of investment. The data allow us to distinguish riskier market-expanding projects from investments in proven markets. We find that private firms more intensely invest in the former type

[18]Unconditionally, about 20% of wells in our sample were filed confidentially. Given that there are no significant costs for petitioning for confidential well status, one may wonder why all wells are not filed confidentially. One potential reason is that firms may be worried that overuse of this tool may lead regulatory agencies to crack down on it - see for example https://tinyurl.com/ybxbu5rf.

projects, while public firms tilt investment towards larger and more efficient pad drilling projects in more well-established areas. We use endowments of legacy leases and proxies for capital availability to link these findings to differential access to financial markets. In summary, our results suggest that lack of access to external financing may encourage, rather than preclude, firms to be more adventurous and bold with their investment mix.

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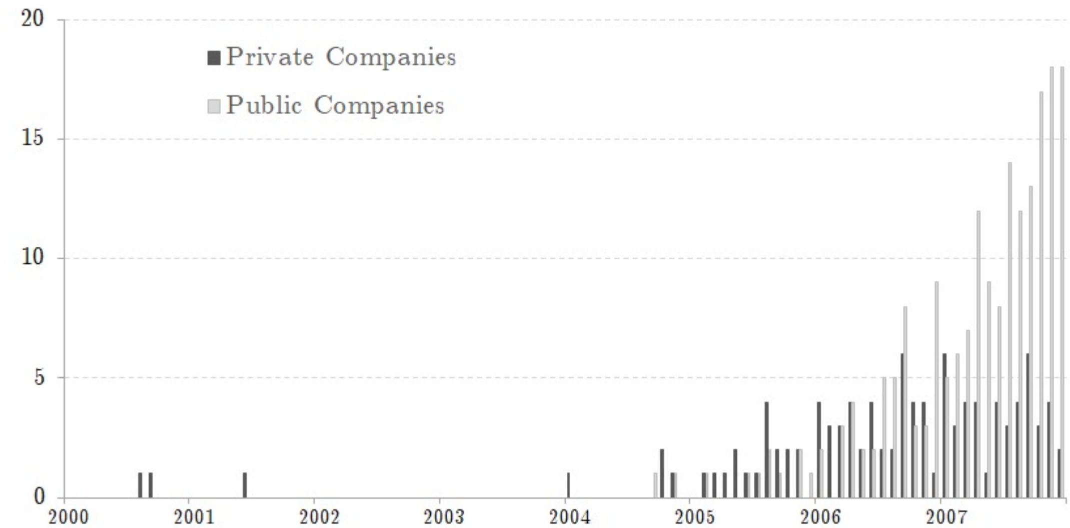
Figure 1: Fracking by Private and Public Companies

In the top panel we show the number of fracks (we define fracking in Section 1) performed in North Dakota over the early part of our sample for both private companies and public companies. In the bottom panel we show the number of fracks performed in North Dakota over our entire sample: 2000-2016. The data come from the North Dakota Industrial Commission.

Number of Fracks



Number of Fracks

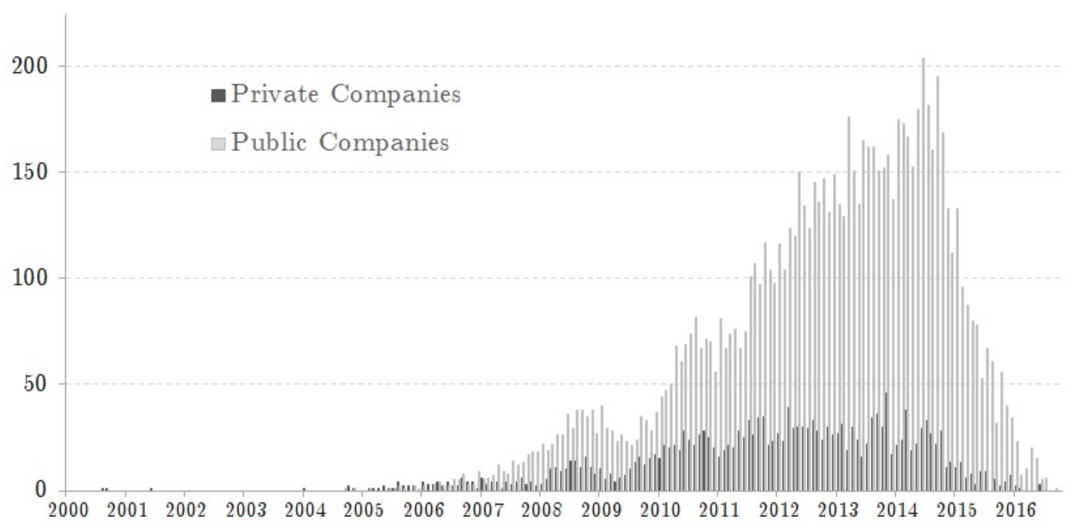
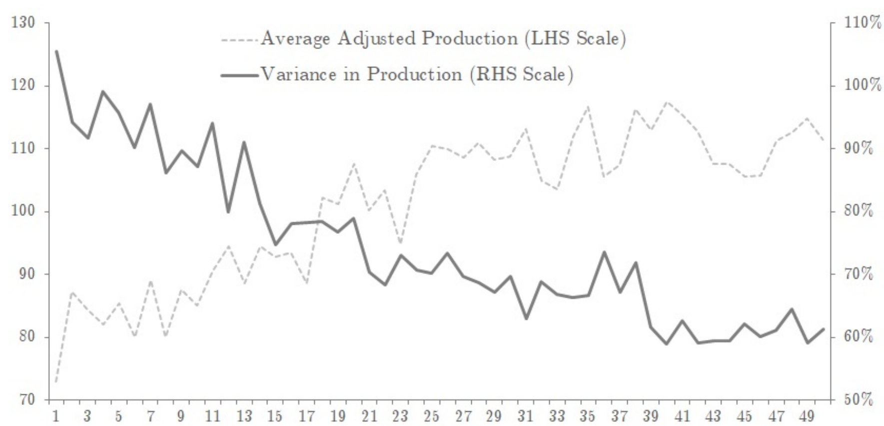


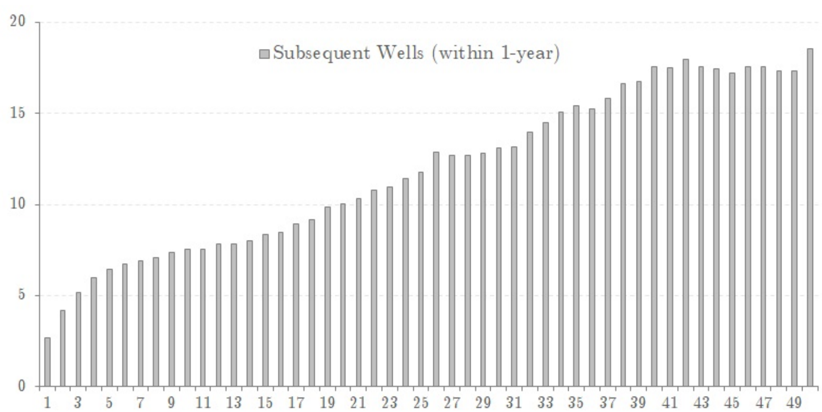
Figure 2: Frontier Wells and Subsequent Wells

In the top panel we show the average well production, and the variance in production, according to the sequence in which wells are drilled in each 6x6-mile township-range grid-square within North Dakota. To adjust for the time trend in well production, we index each well relative to the average production for all wells drilled in each year, which we set to 100. We present the variance in production as the variance divided by the adjusted average. In the second panel we show the average number of subsequent wells drilled, within one year, conditional on the within-area number of oil wells previously drilled. The data come from the North Dakota Industrial Commission for wells drilled between 2000-2016.

Adjusted Production **Variance in Production**



Wells Drilled

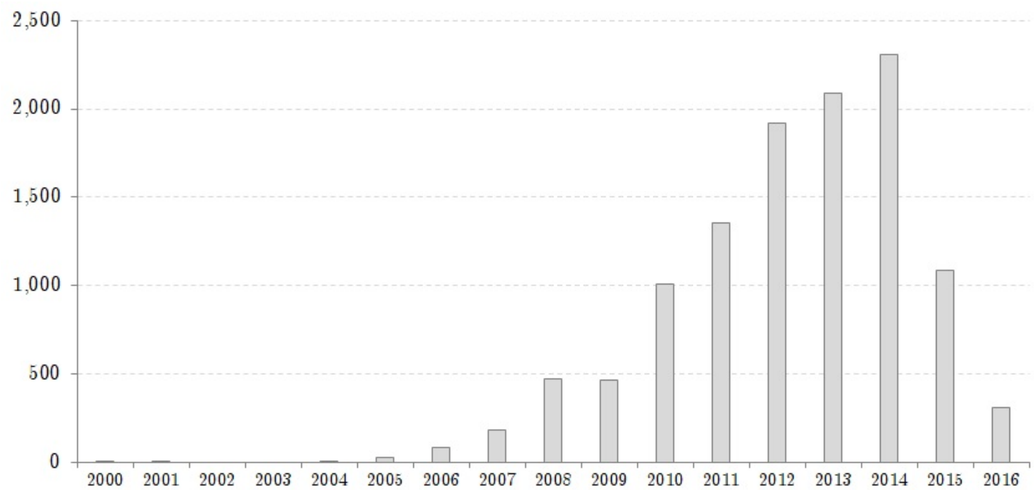


Sequence in which Wells Are Drilled Within-Area

Figure 3: Trends in Fracking, Frontier Fracking, and Pad Drilling in North Dakota

In the top panel we show the trend in the number of fracks in North Dakota. In the bottom panel we show the trends in the share of Frontier $\text{Field}_{i,j}$ fracks as a share of all fracks, and the trend in $\text{Pad2}_{i,j}$ fracks as a share of all fracks. We define these variables in Section 2. The data come from the North Dakota Industrial Commission.

Total Crude Number of Fracks



Share of Fracks

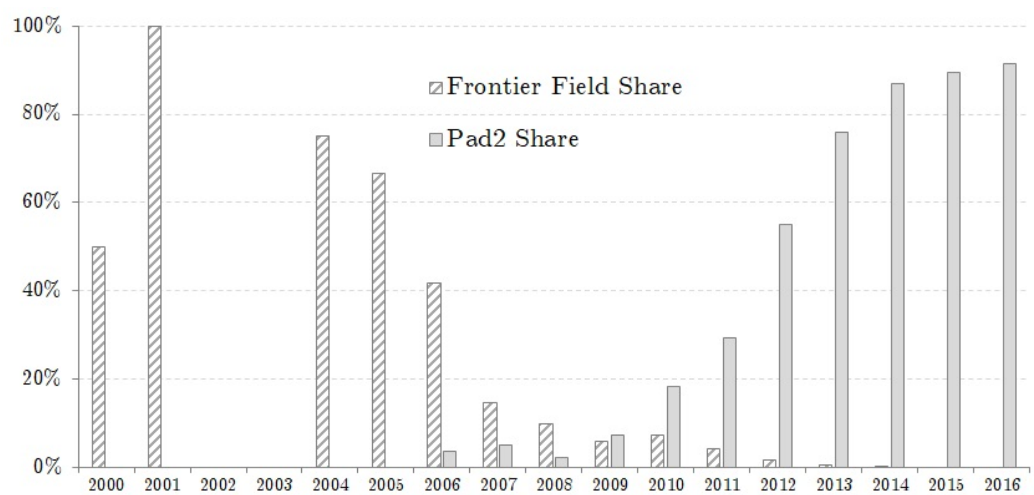


Table 1: Summary Statistics

In this table we present summary statistics for our samples of 11,313 oil wells i drilled and fracked by 98 firms j in North Dakota between 2000-2016. We define all variables in Section 2. The data are from the North Dakota Industrial Commission and CRSP. The below summary statistics reflect the pooled sample of all 11,313 wells as well as variables aggregated at the operator j and quarter t level.

	Mean	Median	Std Dev	Min	Max	n
Well Level Data:						
$\text{Private}_{i,j}$	0.17	0.00	0.37	0.00	1.00	11,313
$\text{Total Depth}_{i,j}$	3.74	3.86	0.38	0.35	5.14	11,313
$\text{Oil Production}_{i,j}$	1,128.35	901.00	827.60	0.00	6,002	11,177
$\text{Drill Days}_{i,j}$	32.09	28.00	36.78	1.00	2,958	11,269
$\text{Frontier Field}_{i,j}$	0.03	0.00	0.17	0.00	1.00	11,313
$\text{Remote Distance}_{i,j}$	0.57	0.12	1.41	0.00	66.90	11,312
$\text{Pad}_{i,j}$	0.58	1.00	0.49	0.00	1.00	11,313
$\text{Confidential}_{i,j}$	0.20	0.00	0.40	0.00	1.00	11,313
Firm Level Data:						
Private_{j}	0.39	0.00	0.49	0.00	1.00	1,173
$\text{Frontier Field Share}_{j,t}$	0.10	0.00	0.25	0.00	1.00	1,173
$\text{Remote Distance}_{j,t}$	1.33	0.64	3.20	0.00	66.90	1,173
$\text{Pad Share}_{j,t}$	0.39	0.22	0.41	0.00	1.00	1,173
Good Lease_{j}	7.67	0.00	26.07	0.00	119.00	706
$\text{Recent Productivity}_{j,t}$	7.40	1.98	12.24	0.00	84.85	1,173

Table 2: Fracking in New Areas

In this table we present regressions examining the propensity to frack in new areas using data aggregated into a panel of firms (j) at quarterly (t) frequency. We measure new areas using two variables: 1) Frontier Field $\text{Share}_{j,t}$ the share of wells drilled by firm j in an oil field as defined by the North Dakota Industrial Commission during quarter t; and 2) Remote $\text{Distance}_{j,t}$ is the average minimum distance, in miles, from well i to all other fracked wells, drilled by firm j during quarter j. The independent variable of interest is Private_j a dummy variable indicating firm j is a private company. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2000-2016 as described in Section 2 aggregated into a panel at the firm (j) level at quarterly (t) frequency. We multiply the dependent variables (save for Remote Distance) by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier Field $\text{Share}_{j,t}$	(2) Frontier Field $\text{Share}_{j,t}$	(3) Remote $\text{Distance}_{j,t}$	(4) Remote $\text{Distance}_{j,t}$
Private_j	5.095**	3.642*	0.609**	0.360**
	(2.081)	(1.837)	(2.216)	(2.128)
Intercept	7.621***		1.091***	
	(6.507)		(9.801)	
Year FE	No	Yes	No	Yes
Cluster Errors	Firm_j	Firm_j	Firm_j	Firm_j
Observations	1,173	1,171	1,173	1,171
R^2	0.010	0.295	0.009	0.426

Table 3: Fracking in New Areas - Entry Wells

In this table we present regressions examining the timing and remoteness of the first well the *entry well* drilled and fracked by each firm into each oil field. We define entry wells as a firm's first well in an oil field g as defined by the North Dakota Industrial Commission. Delay Time$_{j,g}$ is the difference between the firm's entry well drill date and the date of the first well ever drilled in the field. Delay Well$_{j,g}$ is the number of wells that had been drilled in the field prior to the entry well. Remote Distance$_{j,g}$ is the minimum distance, in miles, from the entry well to all other previously fracked well. Remote oDistance$_{j,g}$ is the minimum distance, in miles, from the entry well to any other well fracked by the firm. The independent variable of interest is Private$_j$ a dummy variable indicating firm j is a private company. The data are our sample of entry wells as described in Section 2. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Delay Time$_{j,g}$	(2) Delay Well$_{j,g}$	(3) Remote Distance$_{j,g}$	(4) Remote oDistance$_{j,g}$
Private$_j$	-228.328***	-3.891*	1.011***	3.476**
	(2.207)	(-1.787)	(2.897)	(2.099)
Year FE	Yes	Yes	Yes	Yes
1st Data FE	Yes	Yes	Yes	Yes
Cluster Errors	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$
Observations	1,062	1,062	1,062	993
R^2	0.398	0.237	0.382	0.121

Table 4: Fracking and Legacy Leases

In this table we present the effect of Legacy Leases on a firm's propensity to frack in new areas. We measure new areas using two variables: 1) Frontier Field Share$_{j,t}$ is the share of wells drilled by firm j in a previously undeveloped oil field as defined by the North Dakota Industrial Commission during quarter t; 2) Remote Distance$_{j,t}$ is the average minimum distance, in miles, of each well drilled by firm j in quarter t to all other previously drilled wells. The independent variable of interest is Good Lease$_j$, the number of mineral rights leases in favorable shale locations which were procured for non-fracked, non-Bakken wells drilled prior to 2008. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2008-2016 by firms with operations prior to 2008. We multiply the Frontier Field Share by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier Field Share$_{j,t}$	(2) Frontier Field Share$_{j,t}$	(3) Remote Distance$_{j,t}$	(4) Remote Distance$_{j,t}$
Private$_j$	3.865	4.145	0.166	0.183
	(1.588)	(1.679)	(1.143)	(1.241)
Good Lease$_j$	-0.010	0.180	-0.001	0.010
	(-1.532)	(1.538)	(-1.092)	(1.534)
Good Lease$_j$ × Private$_j$	-0.630**	-0.588**	-0.031**	-0.029**
	(-2.236)	(-2.252)	(-2.066)	(-2.073)
All Lease$_j$		-0.028		-0.002
		(-1.597)		(-1.594)
Year FE	Yes	Yes	Yes	Yes
Cluster Errors	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$
Private Firm Observations	280	280	280	280
Public Firm Observations	426	426	426	426
R^2	0.081	0.085	0.254	0.257

Table 5: Fracking and Legacy Leases - Placebo

In this table we present the effect of Legacy Leases on a firm's propensity to frack in new areas. We measure new areas using two variables: 1) Frontier Field Share$_{j,t}$ is the share of wells drilled by firm j in a previously undeveloped oil field as defined by the North Dakota Industrial Commission during quarter t; 2) Remote Distance$_{j,t}$ is the average minimum distance, in miles, of each well drilled by firm j in quarter t to all other previously drilled wells. The independent variable of interest is Placebo Good Lease$_j$, the number of mineral rights leases in favorable *non-shale* locations which were procured for non-fracked, non-Bakken wells drilled prior to 2008. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2008-2016 by firms with operations prior to 2008. We multiply the Frontier Field Share by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier Field Share$_{j,t}$	(2) Frontier Field Share$_{j,t}$	(3) Remote Distance$_{j,t}$	(4) Remote Distance$_{j,t}$
Private$_j$	3.851	4.512	0.179	0.205
	(1.426)	(1.549)	(1.125)	(1.221)
Placebo Good Lease$_j$	-0.002	0.062**	-0.000	0.002
	(-1.502)	(2.219)	(-1.163)	(1.451)
Placebo Good Lease$_j$ $\times$ Private$_j$	-0.042	-0.065	-0.003	-0.003*
	(-1.301)	(-1.600)	(-1.651)	(-1.732)
All Lease$_j$		-0.046**		-0.002
		(-2.274)		(-1.540)
Year FE	Yes	Yes	Yes	Yes
Cluster Errors	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$
Private Firm Observations	280	280	280	280
Public Firm Observations	426	426	426	426
R^2	0.078	0.084	0.254	0.256

Table 6: Fracking and Legacy Leases - Alternative Explanation

In this table we present the effect of Legacy Leases on a firm's propensity to frack in new areas. We measure new areas using two variables: 1) Frontier Field Share$_{j,t}$ is the share of wells drilled by firm j in a previously undeveloped oil field as defined by the North Dakota Industrial Commission during quarter t; 2) Remote Distance$_{j,t}$ is the average minimum distance, in miles, of each well drilled by firm j in quarter t to all other previously drilled wells. The independent variable of interest is Good Lease$_j$, the number of mineral rights leases in favorable shale locations which were procured for non-fracked, non-Bakken wells drilled prior to 2008. The data are the sub-sample of Bakken wells drilled and fracked in North Dakota from 2008-2016 by firms with operations prior to 2008 which are not within 1 mile of any Legacy Lease owned by the firm. We multiply the Frontier Field Share by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier Field Share$_{j,t}$	(2) Frontier Field Share$_{j,t}$	(3) Remote Distance$_{j,t}$	(4) Remote Distance$_{j,t}$
Private$_j$	3.451	3.904	0.166	0.193
	(1.483)	(1.592)	(1.086)	(1.227)
Good Lease$_j$	-0.006	0.291*	-0.000	0.018*
	(-0.725)	(1.820)	(-0.256)	(1.757)
Good Lease$_j$ × Private$_j$	-0.529*	-0.539**	-0.028*	-0.028*
	(-1.940)	(-2.066)	(-1.873)	(-2.005)
All Lease$_j$		-0.033*		-0.002*
		(-1.842)		(-1.747)
Year FE	Yes	Yes	Yes	Yes
Cluster Errors	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$
Private Firm Observations	269	269	269	269
Public Firm Observations	422	422	422	422
R^2	0.077	0.083	0.242	0.246

Table 7: Booms and Busts by Oil Field

In this table we present regressions examining the likelihood a field is a boom or a bust. In Columns 1 - 2 $Boom_g$ is an indicator equal to 1 if the field is in the the top 20% of well drilling 12 - 48 months after the initial well compared to other fields which began production in the same year. In Columns 3 - 4 $Bust_g$ is an indicator equal to 1 if the field is in the the bottom 20% of well drilling in the 48 months after the initial well compared to other fields which began production in the same year. The independent variable of interest is Private_g a dummy variable indicating the field was first drilled by a private firm. We multiply the dependent variables by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Boom_g	(2) Boom_g	(3) Bust_g	(4) Bust_g
Private_g	-2.752	-2.837	0.632	0.526
	(-0.568)	(-0.563)	(0.126)	(0.104)
Intercept	22.170***		21.698***	
	(7.746)		(7.640)	
Year FE	No	Yes	No	Yes
Observations	315	315	315	315
R^2	0.001	0.002	0.000	0.004

Table 8: Fracking and Recent Productivity

In this table we present regressions examining a firm's propensity to frack in new areas and a firm's reserves. We measure new areas using two variables: 1) Frontier Field Share$_{j,t}$ the share of wells drilled by firm j in an oil field as defined by the North Dakota Industrial Commission during quarter t; and 2) Remote Distance$_{j,t}$ is the average minimum distance, in miles, from well i to all other fracked wells, drilled by firm j during quarter j. The independent variables of interest are Recent Productivity$_{j,t}$, our proxy for each firm's reserves base, which we describe in Section 2.4; Private$_j$ which is a dummy variable indicating firm j is a private company, and the interaction of these variables. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2000-2016 as described in Section 2 aggregated into a panel at the firm (j) level at quarterly (t) frequency. We multiply the dependent variables by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier Field Share$_{j,t}$	(2) Frontier Field Share$_{j,t}$	(3) Frontier Field Share$_{j,t}$	(4) Remote Distance$_{j,t}$	(5) Remote Distance$_{j,t}$
Private$_j$	3.642*	5.273*		0.483**	
	(1.84)	(1.91)		(2.06)	
Recent Productivity$_{j,t}$		-0.042	-0.451***	-0.005	-0.058***
		(-1.14)	(-3.82)	(-1.53)	(-5.26)
Private$_j$×Recent Productivity$_{j,t}$		-0.776**	-0.923***	-0.064*	-0.120**
		(-2.03)	(-2.98)	(-1.96)	(-2.37)
Year FE	Yes	Yes	No	Yes	No
Firm FE	No	No	Yes	No	Yes
Cluster Errors	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$
Observations	1,171	1,171	1,163	1,171	1,163
R^2	0.295	0.299	0.245	0.428	0.215

Table 9: Pad Drilling and Efficiency

In this table we present regressions examining how multi-well pads affect drilling and fracking efficiency. Our proxy for efficiency is Drill $\text{Days}_{i,j}$ which is the number of days from the well i's drill date to the date in which the well's total depth was reached. The independent variable of interest is $\text{Pad}_{i,j}$ an indicator that the well was drilled as part of a multi-well pad. $\text{HDepth}_{i,j}$ is the horizontal depth of the well. $\text{VDepth}_{i,j}$ is the vertical depth of the well. $\text{Laterals}_{i,j}$>1 is an indicator that the well has multiple laterals. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2000-2016 as described in Section 2. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Drill $\text{Days}_{i,j}$	(2) Drill $\text{Days}_{i,j}$	(3) Drill $\text{Days}_{i,j}$	(4) ln(Drill $\text{Days}_{i,j}$)
$\text{Pad}_{i,j}$	-6.498***	-6.576***	-1.708***	-0.070***
	(-9.934)	(-11.032)	(-3.209)	(-6.844)
$\text{HDepth}_{i,j}$		3.945***	4.863***	0.139***
		(7.830)	(10.974)	(14.486)
$\text{VDepth}_{i,j}$		0.311	0.329	0.006
		(0.794)	(0.935)	(0.694)
$\text{Laterals}_{i,j}$>1		13.539***	10.633**	0.193*
		(3.948)	(2.566)	(1.877)
Intercept	35.067***	26.353***		
	(37.402)	(16.977)		
Year FE	No	No	Yes	Yes
Firm FE	No	No	Yes	Yes
Field FE	No	No	Yes	Yes
Rig FE	No	No	Yes	Yes
Cluster Errors	Firm_j	Firm_j	Firm_j	Firm_j
Observations	11,186	11,186	11,186	11,186
R^2	0.038	0.079	0.380	0.387

Table 10: Pad Drilling - Firm Level

In this table we present regressions examining the propensity to drill and frack wells in multi-well pads, which we describe in Section 2 and illustrate in Figure 3. We define Pad Share$_{j,t}$ as the share of wells drilled by operator j during quarter t which two or more wells share the same pad. In Columns (1) and (2) we re-estimate Equation (1) using Pad Share$_{j,t}$ as the independent variable. In Columns (3) and (4) we re-estimate Equation (3) using Pad Share$_{j,t}$ as the independent variable. In Columns (5) and (6) we re-estimate Equation (6) using Pad Share$_{j,t}$ as the independent variable. We multiply the dependent variables by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Pad Share$_{j,t}$	(2) Pad Share$_{j,t}$	(3) Pad Share$_{j,t}$	(4) Pad Share$_{j,t}$	(5) Pad Share$_{j,t}$	(6) Pad Share$_{j,t}$
Private$_j$	-21.147***	-14.624***	-21.629***	-20.613***	-14.611***	
	(-3.87)	(-3.55)	(-3.197)	(-3.077)	(-3.46)	
Good Lease$_j$			0.040*	0.728**		
			(1.931)	(2.112)		
Recent Productivity$_{j,t}$					0.318*	1.987***
					(1.91)	(7.70)
Good Lease$_j$ × $Private_j$			1.494**	1.647**		
			(2.215)	(2.632)		
Recent Productivity$_{j,t}$ × $Private_j$					0.906*	3.182***
					(1.67)	(5.10)
All Lease$_j$				-0.101*		
				(-1.955)		
Intercept	47.244***					
	(14.42)					
Year FE	No	Yes	Yes	Yes	Yes	No
Firm FE	No	No	No	No	No	Yes
Cluster Errors	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$	Firm$_j$
Observations	1,173	1,171	706	706	1,173	1,163
R^2	0.062	0.552	0.564	0.574	0.561	0.558

Appendix A: Supporting Data

Table A1: Individual Company Summary Statistics

In this table we present summary statistics for the most active of the 98 firms in our sample. Our sample of 11,313 oil wells i and firms j spans 2000-2016. We define all variables in Section 2. The data are from the North Dakota Industrial Commission and CRSP.

Firm Name	Private_j	Total Wells Fracked	Total Frontier $\text{Field}_{i,j}$	Frontier Field $\text{Share}_{j,t}$	Total $\text{Pad2}_{i,j}$	Pad2 $\text{Share}_{j,t}$
CONTINENTAL RESOURCES, INC.	0	1195	36	0.03	638	0.53
HESS	0	1146	25	0.02	796	0.69
WHITING OIL AND GAS CO	0	1025	21	0.02	493	0.48
EOG RESOURCES, INC.	0	711	11	0.02	253	0.36
XTO ENERGY INC.	0	639	3	0.00	527	0.82
BURLINGTON RESOURCES	0	595	18	0.03	397	0.67
OASIS PETROLEUM	0	583	11	0.02	358	0.61
MARATHON OIL COMPANY	0	516	7	0.01	269	0.52
STATOIL OIL & GAS LP	0	460	2	0.00	373	0.81
PETRO-HUNT, L.L.C.	1	347	13	0.04	184	0.53
KODIAK OIL & GAS (USA) INC.	0	331	7	0.02	265	0.80
QEP ENERGY COMPANY	0	315	0	0.00	292	0.93
SLAWSON EXPLORATION CO	1	278	5	0.02	160	0.58
NEWFIELD PRODUCTION CO	0	262	10	0.04	179	0.68
SM ENERGY COMPANY	0	251	5	0.02	154	0.61
OXY USA INC.	0	188	2	0.01	98	0.52
FIDELITY E&P CO	1	157	5	0.03	29	0.18
SAMSON RESOURCES COMPANY	0	152	8	0.05	108	0.71
WPX ENERGY WILLISTON, LLC	0	152	0	0.00	137	0.90
HUNT OIL COMPANY	1	145	5	0.03	28	0.19
BRIGHAM OIL & GAS, L.P.	0	138	19	0.14	42	0.30
ZENERGY, INC	1	135	6	0.04	21	0.16
TRIANGLE USA PETROLEUM CO	0	120	1	0.01	105	0.88
ZAVANNA, LLC	1	110	4	0.04	54	0.49
MUREX PETROLEUM CO	1	96	7	0.07	0	0.00

Table A2: Intra-Bakken Dispersion in Quality

In this table present a variance decomposition of determinants of well production. Following Lemmon, Roberts, and Zender (2008) we compute Type III partial sum of squares for each covariate and normalize each estimate by the sum across all covariates, forcing each column to sum to one. Oil Production$_{i,j}$ is the number of barrels of crude oil from well i over the first 24-hours that the well produces. Prop$_{i,j}$ is the amount of proppant used in fracking the well. Laterals$_{i,j} > 1$ is an indicator that the well has multiple laterals. Geography FE are indicators for each 1-mile square plot per the PLSS. The adjusted R-squared for each model is reported at the bottom. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2000-2016 with non-missing covariate data.

	(1) Oil Production$_{i,j}$	(2) Oil Production$_{i,j}$	(3) Oil Production$_{i,j}$	(4) Oil Production$_{i,j}$	(5) Oil Production$_{i,j}$
Geography FE	1.00	0.91		0.87	0.71
Firm FE		0.07		0.07	
Year FE		0.02		0.03	
Firm×Year FE					0.27
Prop$_{i,j}$			0.49	0.02	0.01
Prop$^2_{i,j}$			0.29	0.01	0.01
Prop$^3_{i,j}$			0.20	0.01	0.00
Laterals$_{i,j} > 1$			0.02	0.00	0.00
Adj. R^2	0.574	0.610	0.058	0.617	0.685
Observations	9,133	9,133	9,133	9,133	9,133

Table A3: Fracking in New Areas - Well Level

In this table we present regressions examining the propensity to frack in new areas with our sample of well-level data. We measure new areas using two variables: 1) Frontier $\text{Field}_{i,j}$ which indicates well i drilled by firm j is the first fracked well in an oil field as defined by the North Dakota Industrial Commission; 2) Remote $\text{Distance}_{i,j}$ is the minimum distance, in miles, from well i to all other fracked wells. The independent variable of interest is Private_j a dummy variable indicating firm j is a private company. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2000-2016 as described in Section 2. We multiply the dependent variables (save for Remote Distance) by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier $\text{Field}_{i,j}$	(2) Frontier $\text{Field}_{i,j}$	(3) Remote $\text{Distance}_{i,j}$	(4) Remote $\text{Distance}_{i,j}$
Private_j	3.574***	2.193**	0.439***	0.233***
	(3.122)	(2.436)	(3.417)	(3.113)
Intercept	2.362***		0.493***	
	(7.472)		(12.314)	
Year FE	No	Yes	No	Yes
Cluster Errors	Firm_j	Firm_j	Firm_j	Firm_j
Observations	11,313	11,312	11,312	11,310
R^2	0.006	0.117	0.013	0.346

Table A4: Legacy Lease Summary Statistics

In this table we present summary statistics for the incumbent firm sample used in the legacy lease analysis in Table 4. The data are from the North Dakota Industrial Commission and CRSP.

Private Firms			Public Firms		
Firm Name	Good Lease_j	All Lease_j	Firm Name	Good Lease_j	All Lease_j
PETRO-HUNT, L.L.C.	10	116	HESS	119	1082
BTA OIL PRODUCERS	6	152	ENCORE OPERATING LP	23	174
ARSENAL ENERGY USA INC.	6	39	SM ENERGY COMPANY	8	156
MUREX PETROLEUM CO	1	75	WHITING OIL AND GAS CO	4	123
ZENERGY, INC	1	8	CHESAPEAKE OPERATING INC	1	26
SINCLAIR OIL CORPORATION	1	2	NEWFIELD PRODUCTION CO	1	12
HUNT OIL COMPANY	0	139	CONTINENTAL RESOURCES, INC.	0	33
SAGEBRUSH RESOURCES, LLC	0	67	MARATHON OIL COMPANY	0	33
FIDELITY EXPLORATION	0	56	OASIS PETROLEUM	0	13
TRUE OIL LLC	0	17	ABRAXAS PETROLEUM CORP	0	12
DUNCAN OIL INC	0	16	OXY USA INC.	0	3
SLAWSON EXPLORATION CO	0	11	BURLINGTON RESOURCES	0	2
PRIMA EXPLORATION INC	0	9	DENBURY RESOURCES INC	0	2
SUMMIT RESOURCES, INC.	0	9	EOG RESOURCES, INC.	0	2
ANSCHUTZ EXPLORATION	0	7	KODIAK OIL & GAS (USA) INC.	0	2
PROSPECTIVE INVESTMENT	0	3	SAMSON RESOURCES COMPANY	0	2
CORNERSTONE NAT. RES. LLC	0	1	WILLIAMS COS	0	1
ZAVANNA, LLC	0	1	XTO ENERGY INC.	0	1

Table A5: Fracking and Legacy Leases - Robustness

In this table we present robustness of the effect of Legacy Leases on the propensity to frack in new areas. We measure new areas using two variables: 1) Frontier Field Share$_{j,t}$ is the share of wells drilled by firm j in a previously undeveloped oil field as defined by the North Dakota Industrial Commission during quarter t; 2) Remote Distance$_{j,t}$ is the average minimum distance, in miles, of each well drilled by firm j in quarter t to all other previously drilled wells. The independent variable of interest is Good Lease$_j$, the number of mineral rights leases in favorable shale locations which were procured for non-fracked, non-Bakken wells drilled prior to 2008. In columns (1), (2), (5), and (6), Good Lease$_j$ is defined as a lease within 1 mile of at least 5 fracked wells. In columns (3), (4), (7) and (8), Good Lease$_j$ is defined as a lease within 3 miles of at least 10 fracked wells. We multiply the Frontier Field Share by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) Frontier Field Share$_{j,t}$	(2) Frontier Field Share$_{j,t}$	(3) Frontier Field Share$_{j,t}$	(4) Frontier Field Share$_{j,t}$	(5) Remote Distance$_{j,t}$	(6) Remote Distance$_{j,t}$	(7) Remote Distance$_{j,t}$	(8) Remote Distance$_{j,t}$
Private$_j$	3.891	4.355*	3.620	4.121	0.167	0.199	0.156	0.187
	(1.584)	(1.690)	(1.529)	(1.666)	(1.149)	(1.334)	(1.094)	(1.284)
Good Lease$_j$	-0.006	0.128	-0.002	0.052*	-0.000	0.009*	-0.000	0.003*
	(-1.550)	(1.609)	(-1.495)	(2.004)	(-1.028)	(1.890)	(-1.001)	(1.945)
Good Lease$_j$ × Private$_j$	-0.249**	-0.273**	-0.067**	-0.081**	-0.012**	-0.014**	-0.003*	-0.004**
	(-2.138)	(-2.254)	(-2.079)	(-2.228)	(-2.044)	(-2.255)	(-2.023)	(-2.300)
All Lease$_j$		-0.033		-0.036**		-0.002*		-0.002*
		(-1.660)		(-2.046)		(-1.914)		(-1.973)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Observations	706	706	706	706	706	706	706	706
R^2	0.081	0.086	0.078	0.085	0.254	0.259	0.253	0.258

Table A6: Private Firms and Confidentiality Status

In this table we present regressions examining the likelihood a firm files for confidential stats for a well. $\text{Confidential}_{i,j}$ is an indicator that confidential status was filed for the well. $\text{Frontier Field}_{i,j,t}$ is an indicator that the well is the first in the field. $\text{Oil Production}_{i,j}$ is the initial oil production test of the well in thousands of gallons. The independent variable of interest is Private_j an indicator that firm j is a private company. The data are our sample of all Bakken wells drilled and fracked in North Dakota from 2000-2016 as described in Section 2. We multiply the dependent variables by 100 for coefficient readability. We present T-statistics in parenthesis: *** indicates significance at 1% level, ** indicates 5%, and * indicates 10%.

	(1) $\text{Confidential}_{i,j}$	(2) $\text{Confidential}_{i,j}$	(3) $\text{Confidential}_{i,j}$	(4) $\text{Confidential}_{i,j}$
Private_j	-3.944	-5.461	-5.300	-2.923
	(-0.483)	(-0.664)	(-0.627)	(-0.303)
$\text{Frontier Field}_{i,j,t}$			1.235	
			(0.307)	
$\text{Private}_j \times \text{Frontier Field}_{i,j}$			-3.476	
			(-0.486)	
$\text{Oil Production}_{i,j}$				0.252
				(0.068)
$\text{Private}_j \times \text{Oil Production}_{i,j}$				-3.551
				(-0.755)
Intercept	20.307***			
	(3.465)			
Year FE	No	Yes	Yes	Yes
Observations	11,305	11,305	11,305	11,173
Cluster Errors	Firm_j	Firm_j	Firm_j	Firm_j
R^2	0.001	0.140	0.140	0.136

Figure A1: Crude Oil Prices and the North Dakota Fracking Boom

In the top panel we show the price for West Texas Intermediate (WTI) Crude Oil at the Midland, TX hub as reported by the EIA. In the second panel we show the number of oil wells drilled in North Dakota, as well as the share of wells (by year) of wells that were fracked upon completion. The data come from the North Dakota Industrial Commission for wells drilled between 2000-2016.

WTI Crude Oil Price ($/barrel)

Wells Drilled (bars, left scale) **Share Fracked (line, right scale)**

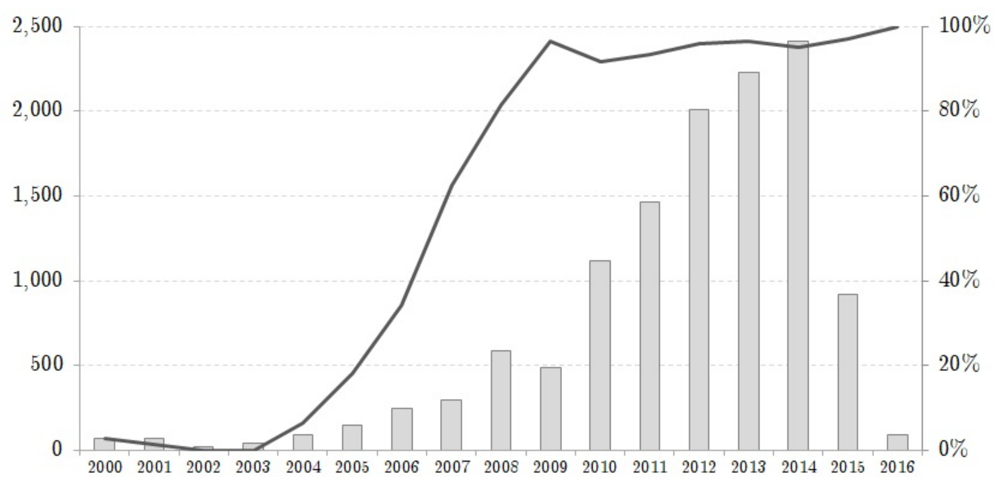


Figure A2: North Dakota Well Production

In this figure we show the average oil production of oil wells drilled in each year in North Dakota. The solid bars indicate production from non-fracked wells, and the striped bars indicate production from fracked wells. The data come from our sample of 11,313 oil which were drilled and fracked, as well as 1,845 oil wells which were drilled but not fracked, between 2000-2016. The data for both fracked and non-fracked oil wells come from the North Dakota Industrial Commission.

Oil Production (first 24 hours, barrels)

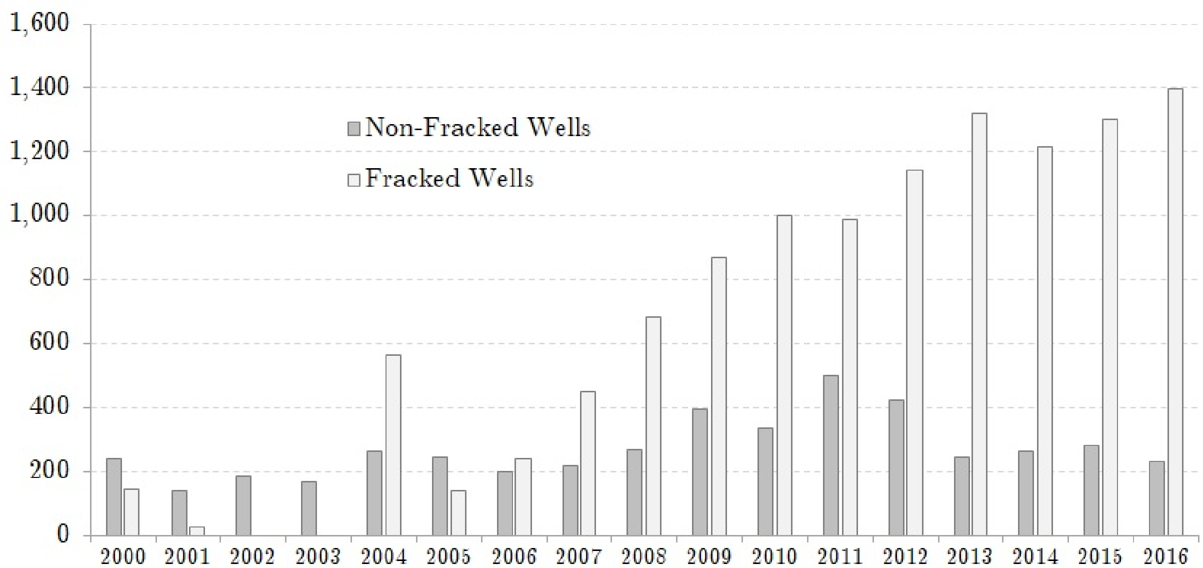
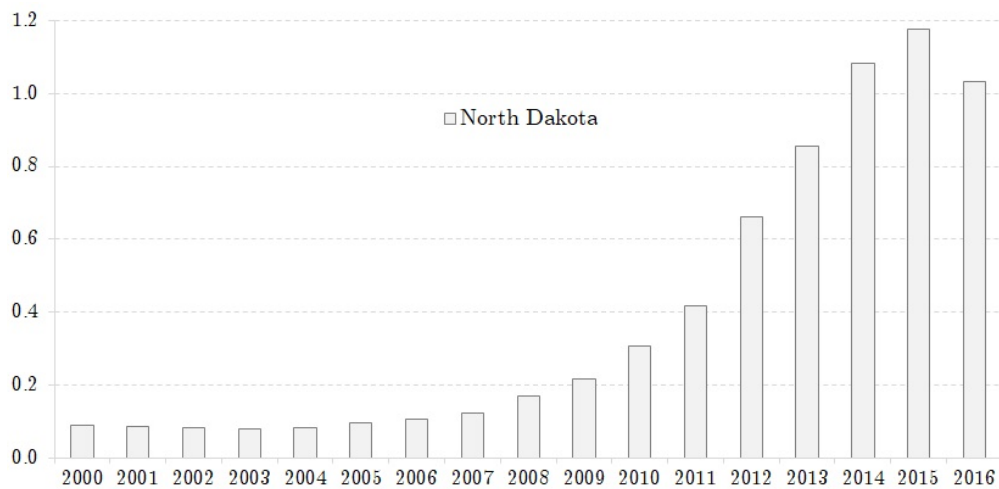


Figure A3: Trends in United States Crude Oil Production, Imports, and Exports

In the top panel we show the trend in the aggregated crude oil production (average barrels/day) for the state of North Dakota. In the bottom panel we show the trend in the aggregated crude oil production (average barrels/day) for the United States. We show the shares coming from North Dakota and Texas which is where oil fracking has been most prevalent. The data come from the Energy Information Agency.

Total Crude Oil Production: North Dakota (Mln barrels/day)



Crude Oil Production: Total United States (Mln barrels/day)

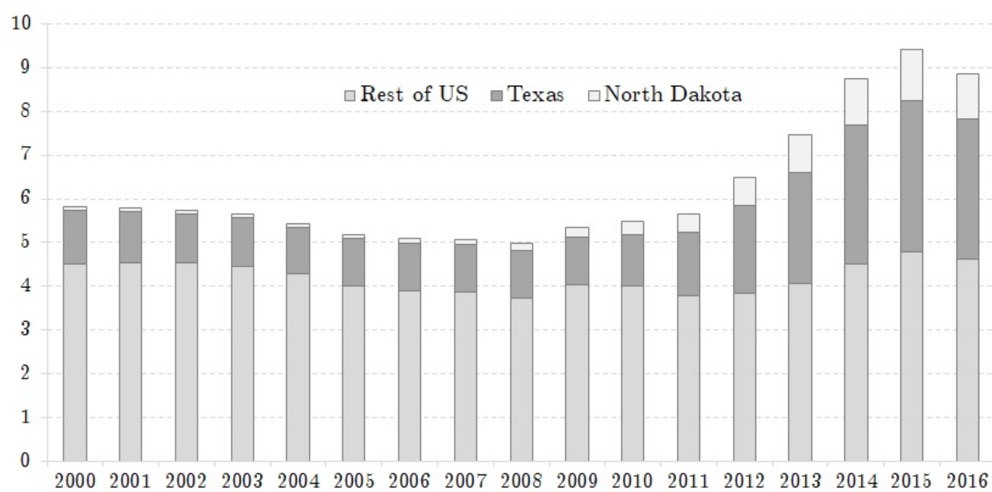


Figure A4: North Dakota Oil Field Map Sample

In this figure we show an image capture from the North Dakota Industrial Commission oil well map server. The red outlines indicate oil fields ("Twin Valley" is an oil field), and the numbered squares are square mile-blocks as indicated by the Public Land Survey System. The black circular dots are oil wells, and the lines extending from the dots indicate subterranean oil-well laterals that extend horizontally. The image represents roughly 24 square-miles.

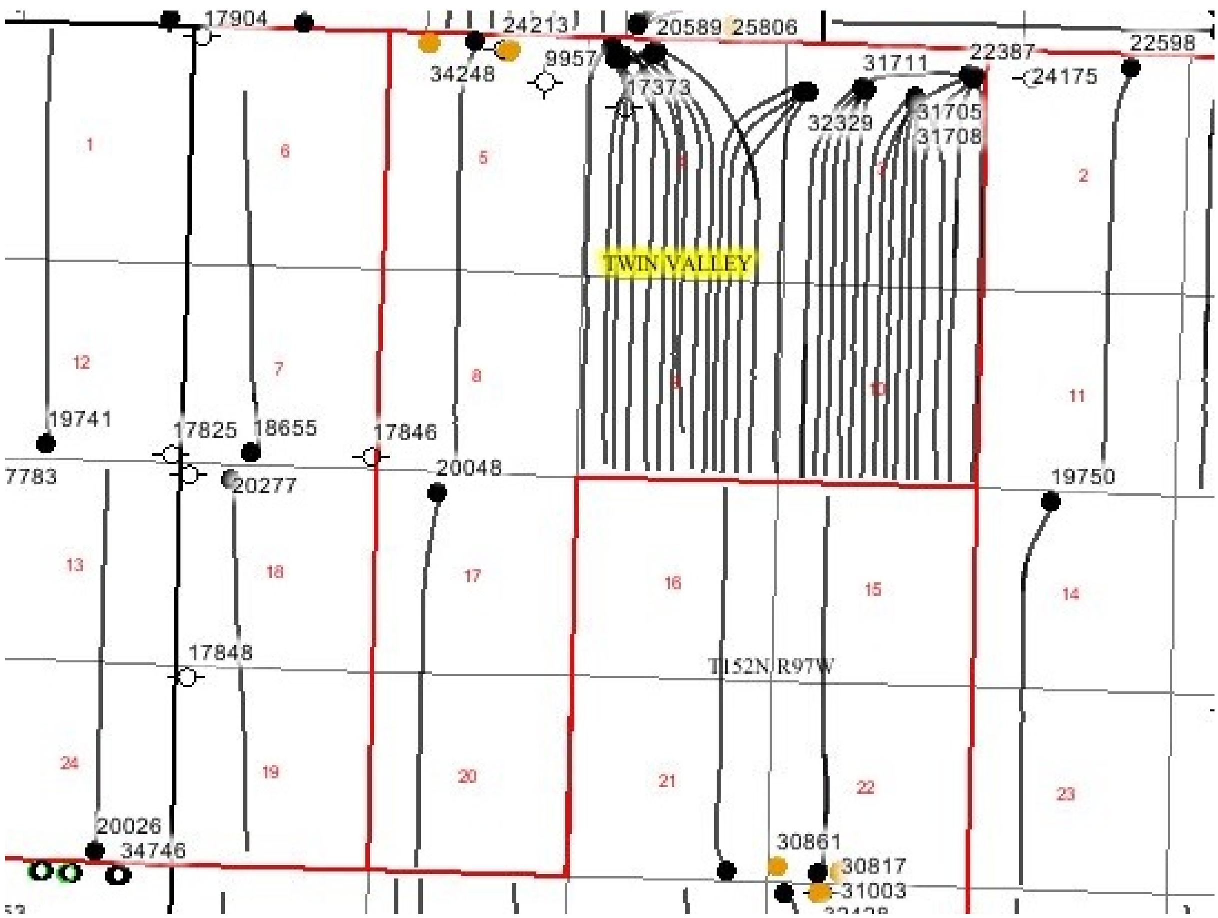


Figure A5: North Dakota Frontier Wells Over Time

In this figure we show the trend in Bakken oil wells drilled and fracked in North Dakota. Each panel shows a map of all oil wells drilled and fracked in North Dakota as of the end of each indicated year. Red dots represent Frontier Field$_{i,j}$ wells drilled and fracked in the respective year. Blue dots represent all other new oil wells drilled and fracked in that year, and black dots represent all oil wells drilled prior to that year. The data come from the North Dakota Industrial Commission.