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Drilling Down the Bakken Learning Curve

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ABSTRACT

Improvements in horizontal drilling have helped unlock U.S. tight oil plays and reverse the decades-long decline in domestic onshore oil production. Whether low oil prices will turn the shale boom into a bust depends in part on how companies have reduced the cost of drilling wells. This paper investigates the role of learning-by-doing in drilling horizontal wells in the Bakken Shale Play. I use a large set of data on oil wells drilled in North Dakota between 2005 to 2014 to measure how firms reduce drilling times as they acquire experience. The results show that as firms gain experience in the Bakken, they drill wells faster. A doubling of a drilling rig's experience leads to a 5% reduction in the time to drill a well, which translates into a cost savings of about $31,000 per well. Given that on average a rig drills eight wells per year in the Bakken, a rig is expected to reduce the time it takes to drill a well by 11% over its first year of drilling. These findings have implications for how the current low oil price environment will affect U.S. drilling activity. Furthermore, there is evidence of organizational forgetting by rigs resulting from breaks in between drilling wells, which suggests productivity will be negatively impacted if and when drilling activity rebounds. Lastly, I find no evidence of learning spillovers across firms. This result implies that firms internalize the knowledge gained that is relevant for reducing drilling times in subsequent wells, and it has implications for social welfare and the use of fossil fuel subsidies.

1 Introduction

The recent boom in U.S. oil production is largely due to advances in horizontal drilling, hydraulic fracturing, and 3D seismic imaging that have brought down costs and increased well production. This paper focuses on one of these advances, horizontal drilling, within the U.S. Bakken Shale Play. At the start of 2005, there were just under 200 wells producing oil in the Bakken, and by the end of 2014, that number reached nearly 9,000 (NDIC, 2015b). With oil prices at levels not seen since the Great Recession, there is considerable speculation whether this "tight oil revolution" can continue. Will low oil prices stifle drilling activity and turn the shale boom into a bust? The answer depends in part on how the cost of drilling has declined.

This paper uses a large set of well-level data to determine the role of learning-by-doing in drilling horizontal wells in North Dakota's Bakken Shale Play. The speed in which a well is drilled, measured as the well's depth divided by the number of days spent drilling, proxies for the productivity of drilling. To measure learning, I quantify how the time required to drill a well decreases as firms increase their experience. Moreover, following past literature on learning-by-doing, I investigate forgetting and learning spillovers across firms.

The concept of learning-by-doing, wherein productivity rises or unit cost declines as firms increase their production experience, appears in several areas of economic literature as well as management science and engineering. Wright (1936) estimated how aircraft manufacturing costs declined with experience and is often cited to be the first to formalize the concept mathematically. Arrow (1962) described organizational learning and established its importance to endogenous growth theory. There are numerous theoretical articles and empirical investigations of learning-by-doing (Thompson (2012) provides a comprehensive review of the literature). Kellogg (2011) investigates the role of learning-by-doing in drilling vertical wells in Texas. He finds evidence for relationship-specific learning between operating companies, which own and design wells, and the rigs that are contracted to drill wells. Osmundsen et al. (2012) find mixed evidence for learning when analyzing drilling in the Norwegian Continental

Shelf.

This paper makes three primary contributions to the literature. It is the first to analyze learning-by-doing in horizontal drilling operations within a shale play. Horizontal drilling involves different techniques and technology than vertical wells, and given that analyses of onshore and offshore drilling find dissimilar results, one cannot simply extrapolate conclusions from one type of drilling operation to another. Tight oil is an increasingly important source of global oil production, and shale plays are believed to contain sizable hydrocarbon resources (EIA, 2013). This analysis improves our understanding of how higher productivity can unlock once uneconomic oil and gas resources.

Second, it evaluates a new and booming production activity that gives rise to opportunities for learning spillovers. While prior studies of other industries find evidence for spillovers (Benkard, 2000; Conley and Udry, 2010; Irwin and Klenow, 1994), Kellogg (2011) finds no evidence for learning spillovers when analyzing drilling in Texas from 1991 to 2005. This may be a result of the maturity of Texas oil fields over the sample period, given that oil production in Texas began in the 19th century. In contrast, very few horizontal wells were drilled in the Bakken prior to the start of my sample period (2005-2014). The relatively high concentration of activity in the Bakken could also create spillovers that are not observed in other oil basins. One might anticipate the mechanism of spillovers in oil fields is similar to the hypotheses noted by Glaeser and Resseger (2010) in explaining the positive relationship observed between metropolitan size and productivity: in denser cities, knowledge transfers occur more easily among workers and ideas spread faster to boost productivity.

Third, this paper improves our understanding of how the cost of drilling within U.S. shale plays is evolving over time and the impact of organization forgetting on overall drilling costs. This has implications for how U.S. drilling activity will respond to the current low oil price environment and in turn the future of domestic oil production and job growth in the oil and gas sector.

There are three main findings on the role of learning-by-doing in drilling horizontal wells in the Bakken. First, drilling productivity (depth drilled per day) increases as rigs increase their experience and as operators gain experience within a field. A doubling of a rig's experience decreases the days required to drill a well by 5.0%, and a doubling of an operator's experience within a field decreases drilling time by 1.9%. These rates of learning translate to cost savings of $31,000 and $12,000, respectively, for a typical well.[1] On average a rig drills 8 wells per year, implying that in a rig's first year of drilling, its learning results in an 11% reduction in drilling time and costs. Second, I estimate the effect of organizational forgetting that occurs due to breaks between when a rig finishes drilling one well and begins another. A doubling of the duration of a rig's break increases the time to drill the next well by 1.5%. Third, and finally, despite the high concentration of drilling operations in the Bakken, I find no evidence for learning spillover across firms.

Section 2 provides an overview of drilling operations in the Bakken. Section 3 summarizes the data and procedures for compiling the data set. Section 4 describes the statistical methods, and Section 5 details potential identification issues. Section 6 presents the result of the regression analysis. Sections 7 and 8 investigate the role of forgetting and learning spillovers, respectively. Lastly, Section 9 concludes on the findings and implications of this work.

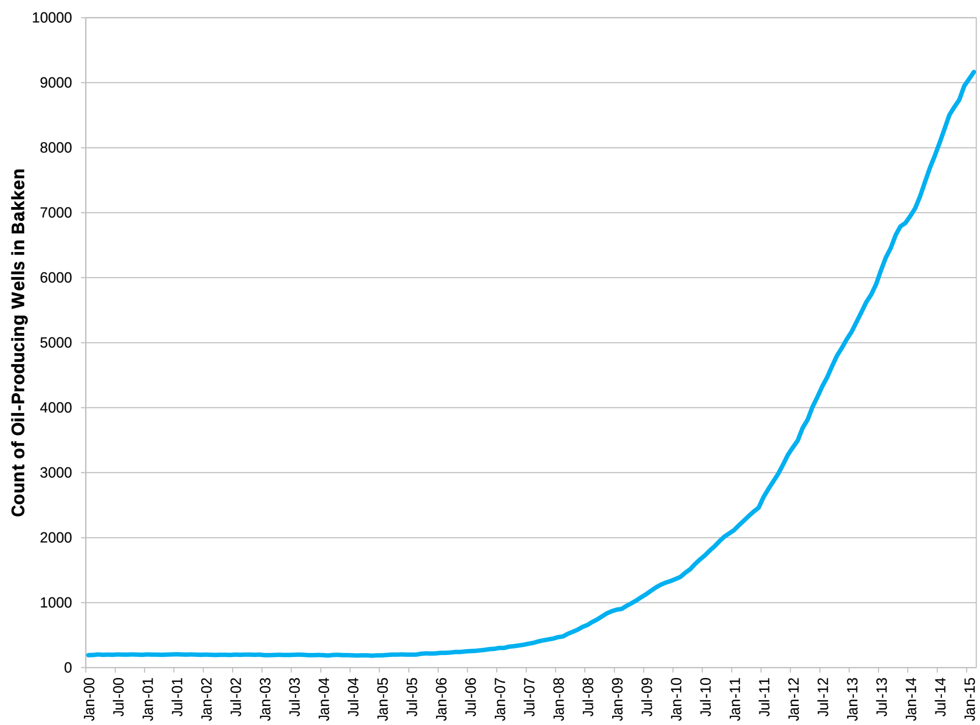
2 Overview of Drilling Operations in the Bakken

Drilling in North Dakota is concentrated in the Williston Basin, a hydrocarbon-rich depression spanning 150,000 square miles and reaching into Canada, Montana, and South Dakota (NDGS, n.d.). Nearly all wells drilled in North Dakota within the Williston Basin target the Bakken and Three Forks formations, located about 10,000 feet below ground. The Bakken and Three Forks are termed unconventional tight oil plays due to their low permeability (i.e. fluids cannot easily flow through the rock) and low porosity (i.e. there is limited void space

[1] This is based on a daily rig cost of $24,000 (RigData, 2012) and the sample mean of 26 days to drill a well.

within the rock) (Sorensen and Terneus, 2008). While oil was first produced from the Bakken in 1955 (EERC, 2014), much of the oil present could not be economically extracted until recently. Figure 1 shows that Bakken activity was flat during the early 2000s with no growth in the number of oil-producing wells. In 2005, the horizontal well "Nelson Farms 1-24H" was drilled by EOG Resources in the Ross Field. The success of this well is considered to be a turning point in that it showed how combining horizontal drilling and hydraulic fracturing could unlock the Bakken's once uneconomic hydrocarbons (EERC, 2014).

Figure 1: Oil-Producing Wells in the Bakken (January 2000- January 2015)



Several firms are involved in the process of drilling an oil or gas well, and learning can be expected to occur within each firm. The operating company or operator owns the right to drill the well and produce oil and gas.[2] The operator contracts out drilling to a "drilling contractor" that provides the rig and crew to drill the well. Rigs contain several components,

[2]In North Dakota and throughout the U.S., companies acquire the right to drill for and produce oil through a lease agreement with the owner of the subsurface resources. The operator may be the exclusive lease holder of a specific acreage or acting on behalf of other lessees.

most prominently the pyramidal shaped mast or derrick that supports the pulley system, motor, and drillstring (a series of large steel pipes). The drillstring is rotated by a motor and a drill bit that is attached to the end cuts and crushes the rock to make the wellbore. As drilling progresses and the well's depth increases, crews add more drill pipe to the drillstring. Baker (2001) describes several key personnel on a rig crew. "Roughnecks" help handle the drill pipe as it is lowered to the hole and connected to the drillstring. "Drillers" operate the controls and oversee the drilling crew, and the Rig Superintendent or "toolpusher" oversees the entire rig and coordinates with the operator's representative on the rig. Learning may result from crews increasing their proficiency at operating equipment or toolpushers more effectively managing rig operations. For example, tools or drillpipe can fall into the wellbore and require operations to stop while they are removed. Preventing these events or mitigating their delay may be one source of learning.

The operator typically creates the drilling program, which is a detailed plan for how the well will be constructed (Fraser, 1991). Several decisions made in planning a well can influence the speed in which it is drilled, such as the well path, drilling mud, and drill bits. Operators can adjust a well's path to avoid geologic features, such as faults and folds, that may cause problems while drilling. Mud serves many purposes in drilling, most notably it counteracts the pressures from underground geologic formations. The properties of a mud (e.g. its density) affect the speed of drilling, and different types of muds and additives are selected depending on the characteristics of the formations encountered while drilling. Drill bits are used to cut and crush rock and make the hole, and different bits can be used for specific formations being drilled; geologic formations have varying degrees of "drillability" and experiences in nearby wells can be useful in deciding which bit types to use (Fraser, 1991). Much of an operator's potential learning appears to come from acquiring experience with drilling wells through specific geologic formations, and thus their learning may be specific to certain areas within the Bakken. That is, an operator's experience within a particular oil field in the Bakken may not be relevant to wells drilled in other fields in the Bakken or even other areas of the same field.[3] This contrasts with learning by rigs, which is likely transferable across fields.

Traditionally, most oil and gas wells have been drilled only vertically. The first horizontal well was drilled in Texas in 1929, but this technique did not become common until the 1980s (King, 1993).[4] In drilling a horizontal well, the wellbore is first drilled vertically, and then at the "kickoff point" it begins deviating from its vertical orientation. A typical well in the Bakken may have a kickoff point that is 10,000 feet below ground and a horizontal section that is 10,000 feet in length. To drill the horizontal section of a well, in addition to the rig, a directional drilling company is hired. The directional driller uses special equipment positioned at the end of the drillstring that allows the wellbore to be drilled horizontally. Learning by directional companies may occur as they gain experience with drilling through geologic formations within a field, improve proficiency with tools and equipment, or prevent drilling interruptions. I examine model specifications where learning by directional companies is specific to a field and not field-specific.

When an operator contracts with a company to drill a well, a dayrate or daywork contract is most often used. This type of contract is structured so that the drilling contractor is paid by the operator for the number of days spent drilling. This suggests that the rate in which a well is drilled is related to the cost of drilling, and it supports using the rate of drilling as a measure of productivity. Moreover, speed is considered a key measure of drilling efficiency (Cochener, 2010), and it is the viewpoint within the industry that the time required to drill a well is correlated with cost, "In the drilling industry, everyone knows that time is money." (Halliburton, 2015).

[3] A field consists of one or more accumulations of oil or gas that share a common "geological structural feature and/or stratigraphic condition" (EIA, 2015).

[4] Advantages of horizontal wells include the ability to drill multiple wells from one location, a smaller surface footprint, and increased production by exposing more of wellbore to the reservoir (Short, 1993).

3 Data

The data set used in this analysis includes only horizontal wells drilled in the Bakken and Three Forks formations from 2005 through part of 2014. Summary statistics are presented in Table 1. There are a total of 4,404 wells drilled from 2005 to 2014 that are included in the regression analysis. The mean rate in which a well is drilled is 830 feet per day, with a minimum of 132ft/day and a maximum of 2,063ft/day. The mean number of days to drill a well is 26 with a minimum of 8 days and a maximum of 157 days. Table 1 shows two measures of a well's depth, measured depth (MD), which is the length of the well from the surface to the bottom, and true vertical depth (TVD), which is the vertical distance from the surface of the well to the bottom. MD is the actual footage drilled and is used when calculating the rate of drilling the well. The mean TVD of 10,268 feet and standard deviation of 774 indicate there is not a substantial amount of variation in the vertical depths of wells in my sample.

Information on a well's spud date (i.e. when the drill bit hits the earth and drilling begins), total depth date (i.e. when total depth is reached and drilling ceases), MD, TVD, operator, and field are sourced from Drillinginfo, an online provider of oil and gas data and analytics tools. The name of the rig used to drill the well and the directional drilling company hired are from information reported by well operators to the North Dakota Industrial Commission (NDIC) Oil and Gas Division. Temperature and wind data are sourced from the National Atmospheric and Oceanic Administration (NOAA).[5]

The number of days spent drilling is initially calculated as the difference between the total depth date (the date drilling ended) and the spud date (the date drilling began). There are

[5]NOAA temperature and wind data are used to calculate the average daily ambient temperature and average daily maximum wind speed during the course of drilling a well. There are six weather stations in western North Dakota that report daily temperature and wind speed: Bismark Municipal Airport, Dickinson Theodore Roosevelt Regional Airport, Garrison, Hettinger Municipal Airport, Minot International Airport, and Williston Sloulin Field International Airport. Weather data from the station nearest the well is used to calculate the average temperature and wind speed.

Table 1: Summary Statistics

	Mean	Median	Std. Dev.	Min.	Max.
Rate (feet/day)	830	796	293	132	2,063
Drilling Time (days)	26	24	10	8	157
Measured Depth (feet)	19,394	20,130	2,131	9,289	26,908
True Vertical Depth (feet)	10,260	10,463	774	6,901	14,945
Temperature (Celsius)	-1.0	-0.2	10.9	-25.3	17.1
Wind Speed (m/s)	4.0	3.9	0.8	2.1	8.3
Rig Experience (wells)	15	12	12	1	63
Operator-Field Experience (wells)	26	7	53	1	324
Dir. Co.-Field Experience (wells)	13	4	26	1	174
Field Experience (wells)	48	18	74	1	414

Note: Sample includes 4,404 wells drilled between 2005-2014. There are a total of 313 rigs, 62 operators, 44 directional companies (Dir. Cos.), and 269 fields.

four issues, which are discussed below, that complicate using this difference as a measure of the days spent drilling. To deal with these issues, I use information reported to the NDIC by operators to verify the number of days spent drilling and the depth drilled. I inspect all observations with a difference between the total depth date and the spud date that is relatively large (greater than 40 days) or relatively small (less than 14 days). The first issue is that wells may have multiple lateral "legs" rather than just a one horizontal section. This will increase the apparent number of days taken to drill to a given depth. For these wells, drilling time and MD are set equal to the days spent drilling the first horizontal section and that section's depth. Second, a well may be drilled at a particular time and then re-entered at a later date to continue drilling. In these cases, I use the days spent drilling and MD for the original wellbore drilled and do not include the re-entry as an observation. Third, it is not uncommon for a small rig to start a well and a larger rig to finish drilling. These smaller rigs, called spud rigs, are used to drill the vertical "surface hole", which is often about 2000 feet deep. Using the difference between the total depth date and spud date will include any break between when the spud rig finished the surface hole and the larger rig began drilling, thus overstating the true number of days spent drilling. For wells that use a spud rig, I measure the drilling rate using the days spent drilling by the larger rig and the well's MD, and the regression analysis will control for the effects of using a spud rig. Fourth, some operators in the Bakken use a procedure called "batch drilling" to drill multiple wells on the same well pad. In batch drilling, a rig is used to drill the surface hole for each well on the pad sequentially, then the vertical sections are drilled followed by the lateral sections. This causes the difference between the total depth date and spud date to overstate the true drilling time since it includes time spent drilling other wells on the same pad. For these wells, I exclude days spent drilling other wells on the pad.

Initially, there are a total of 8,230 observations, where each represents a well that has been drilled, and 4,404 wells are ultimately included in the estimation. Observations are lost for several reasons. For 1,894 wells, either the spud date or total depth date is not available from Drillinginfo. In these cases, Drillinginfo reports the well has been drilled but does not provide the dates drilling began or finished. Of the remaining 6,336 observations, the number of days spent drilling cannot be determined for 451 wells. These observations were dropped because one of the four issues mentioned in the prior paragraph (i.e. multilateral, re-entry, spud rig, or batch drilling) was identified in reviewing information submitted to the NDIC by the well operator and the days spent drilling could not be determined. Thirteen additional observations are lost because the well's depth is not reported. 439 wells of the remaining 5,872 observations do not have a field identified or are considered wildcat wells. Since the field in which a well is drilled is used as a control, these observations are excluded. The estimation results are not significantly different when these wildcat wells are included (Table 5 of Appendix). Lastly, of the remaining 5,433 wells, 1,029 are excluded because either the well's rig or directional drilling company cannot be identified. When these observations are included in the estimation by dropping the rig and directional drilling company experience variables, the statistical significance of the coefficients for the remaining experience variables are unchanged (Table 5 of Appendix).

4 Estimation

Equation 1 presents the learning-by-doing model, where I follow past literature in using a log-log form.[6] The dependent variable is the natural log of the measured depth of the well (in thousands of feet) divided by the days spent drilling. As previously mentioned, drilling contracts are often "dayrate", wherein the drilling contractor is paid based on the number of days they spend drilling. Hence, the rate of drilling (i.e. depth per day) is likely well correlated with the cost of drilling.

$$LnRate_{rodft} = \alpha_0 LnE_{rt} + \alpha_1 LnE_{oft} + \alpha_2 LnE_{dft} + \alpha_3 LnE_{ft} + \beta X_{rodft} + \phi_r + \psi_o + \zeta_d + \kappa_f + \lambda_t + \epsilon_{rodft} \quad (1)$$

For the well drilled by rig r, operator o, and directional company d in field f at date t, $Rate_{roft}$ is that well's depth (in thousand feet) divided by the number of days spent drilling. Each observation corresponds to a well drilled, so the dependent variable is the average rate in which the well was drilled and not the rate of drilling over a set time period such as a month or year. X_{rodft} is a vector of control variables. The parameters ϕ_r, ψ_o, ζ_d, and κ_f, are rig, operator, directional company, and oil field fix effects. The parameter λ_t encompasses a year-quarter fixed effect (2005Q1, 2005Q2, etc.) and month of year fixed effect (January, February, etc.), and ϵ_{rodft} is the idiosyncratic error term.

The variable E_{rt} is the experience of rig r within the Bakken and measured as the cumulative number of wells drilled by rig r prior to finishing the well spud on date t. The experience variables E_{oft} and E_{dft} correspond to the experience of operator o in field f and directional company d in field f, respectively. As discussed in Section 2, learning by operators and directional companies may be based on acquiring experience within a particular

[6]Most learning-by-doing models have the log of unit cost or labor input requirement as the dependent variable and logged experience variables as regressors along with several controls. Thompson (2010) gives a brief review of its theoretical basis.

field, and experience in one field may not be relevant in another. This contrasts with learning by rigs, which results from gaining experience with drilling equipment and procedures. Table 5 of the Appendix includes a specification with experience variables for operators in all fields (E_{ot}), directional companies in all fields (E_{dt}), and rigs within a field (E_{rft}). None of the coefficients for these variables is statistically significantly different from zero at any reasonable significance level. The variable E_{ft} is the cumulative number of wells drilled within field f. This measures the effect of aggregate experience of all firms in a field on drilling productivity and can capture evidence of learning spillovers.

There are two alternative ways to measure experience: cumulative number of feet drilled and cumulative number of days spent drilling. The cumulative number of days spent drilling is somewhat consistent with theoretical models of learning that measure experience as cumulative investment (See Thompson (2010)). Using either the number of wells drilled or feet drilled is consistent with the vast majority of the learning-by-doing literature that measures experience based on cumulative output. These different measures of experience highlight that any variable is merely a proxy for true experience. Accordingly, it may be useful to look to studies on drilling efficiency in petroleum engineering literature for guidance; this literature consistently uses the number of wells previously drilled (Jablonowski et al., 2011; Li et al., 2010; Perry, 1992; Rampersad et al., 1994; Studer, 2007). The Appendix provides the results of alternative experience measures. The results are similar when using the cumulative number of feet drilled or when restricting experience to the wells drilled within the last two years.

The control variables in Equation 1 include the well's true vertical depth (TVD), measured depth (MD), MD squared, and MD cubed to allow the rate of drilling be non-linear in well depth. Additionally, the average ambient temperature and maximum wind speed over the drilling period are included to account for the effects of weather. Sufficiently high winds or low temperatures are reported to halt drilling operations (Spiess, 2014). All wells in the sample are drilled into either the Bakken or Three Forks formation, and a dummy variable for the targeted formation is also included. Lastly, a final control variable is a dummy for whether a spud rig was used to start the well divided by the well's MD, which allows for the effect of using a spud rig to varying with the well's depth.

5 Identification

Potential threats to identification and the sources of variation are considered in this section. First, it is likely there are unobservables correlated with the experience regressors, thus creating an endogeneity issue. Including fixed effects in Equation 1 controls for time-invariant unobservables specific to each firm or oil field, such as quality of management and technological capabilities of a firm or geological characteristics of a field. The year-quarter fixed effects control for Bakken-wide changes that influence drilling speeds, such as technological advances, as well as unobservable effects specific to a particular quarter.

Second, as in any empirical analysis there is some degree of measurement error. There may be measurement errors resulting from misreporting or inaccuracies in the dataset. There are reasons to have a high degree of confidence in the quality of the datasets used in this analysis. As mentioned in Section 3, the data sources are the North Dakota Industrial Commission (NDIC), which is the regulatory body overseeing drilling operations, and Drillinginfo, which sources the data relevant to this analysis from the NDIC. Drillinginfo is a subscription-based service, and likely has a strong interest in maintaining the integrity of its data. Another measurement error results from the fact that the experience regressors are only proxies for true experience. Section 4 discusses the rationale for using the number of wells previously drilled as the measure of experience. Nonetheless, this measurement error creates an unavoidable attenuation bias, which is true in most empirical learning-by-doing studies.

Third, endogeneity can occur in learning-by-doing models from serial correlation in the error terms and the use of cumulative output to measure experience. In typical learning models, output is observed over set time periods (e.g. months or years). A serial correlated shock in the current period affects the dependent variable (e.g. labor-input requirement) and in turn the cumulative level of output (experience) in the next period. This creates a correlation between the experience variable (cumulative output) and the error term. This analysis is slightly different in that I do not observe a per-period output level but rather the unit of observation is a well. For this reason, and because I use total cumulative experience, serial correlated shocks do not create an endogeneity issue here. As wells are drilled sequentially, if there is a serial correlated shock that increases the number of days it takes to drill one well, this does not affect the number of wells finished by the time next well is started.

Fourth, and finally, there may be endogenous matching among firms. Kellogg (2011) discusses how unobservable firm characteristics may lead certain operators and rigs to drill wells together and also increase the speed in which their wells are drilled. If not accounted for, this endogenous matching could create the appearance of relationship-specific learning, wherein the joint experience of an operator and rig increases drilling speeds. Table 5 in the Appendix shows the results when a variable for joint operator-rig experience is added to Equation 1. While the coefficient estimate for this variable is positive, it is not statistically indistinguishable from zero at any reasonable significance level (p-value=0.312). The presence of endogenous matching would cause the coefficient for the operator-rig experience variable to be biased upward (away from zero). Since the coefficient estimate is insignificant, this suggest endogenous matching is not a concern. Table 7 summaries the distribution of rig, operator, directional drilling company, and field pairings. It shows that rather than matching up with just one of company, firms usually contract with multiple companies and drill wells in several different fields.

Several sources of variation exist for identifying the effects of experience on the rate of drilling. Breakthroughs in hydraulic fracturing that allowed extraction of known but previously uneconomic resources, discoveries of new fields within the Bakken, and fluctuations in oil prices are primary drivers of variation in drilling activity over time. The relatively harsh North Dakota winter also creates seasonal fluctuations in drilling activity. Variation in firm and field-level experience results from operators employing several rigs and directional drilling companies simultaneously. Rigs also contract with multiple operators, and directional drillers are employed by several operators both simultaneously and over time. Often there is more than one operator within a field, and operators typically drill wells in multiple fields (Table 7).

6 Results

The regression results for Equation 1 are presented in Table 2 with the last column including all experience variables. The coefficient for logged rig experience is 0.072 and statistically significantly different from zero at the 0.1% level. This estimate suggests that a doubling of rig experience leads to a 7.2% decrease in the time required to drill a well. The coefficient for logged operator experience within a field is 0.021 (significant at the 1% level), suggesting that a doubling of operator experience leads to a 2.1% decrease in the days required to drill a well. The coefficients for the directional company experience within a field variable and the aggregate experience in a field variable are not significant at any reasonable significance level. The insignificant effect of aggregate field-level experience suggests that learning spillovers do not occur among the firms within a field.

The magnitudes and signs for the control variables appear to be reasonable and consistent with intuition. The coefficients for the measured depth variables are significant at either the 1% or 0.1% levels. The coefficients for the temperature and wind variables indicate that, as expected, lower temperatures or higher winds speeds reduce the rate of drilling. While not shown in Table 2, the coefficient estimate for the spud rig control variable is positive and statistically significantly different from zero (at the 0.1% level), as anticipated, since use of a spud rig reduces the time the primary rig must spend drilling.

Table 2: Regression Results- Learning-by-Doing

	Rig Experience	Rig & Operator-Field	Rig Operator-Field, & Dir. Co.-Field	Equation 1
Regressor	*LnRate*	*LnRate*	*LnRate*	*LnRate*
LnE_{rt}	0.080***	0.071***	0.069***	0.072***
	(0.012)	(0.011)	(0.011)	(0.011)
LnE_{oft}		0.022**	0.017**	0.021**
		(0.007)	(0.008)	(0.008)
LnE_{dft}			0.009†	0.002
			(0.005)	(0.008)
LnE_{ft}				-0.009
				(0.013)
Depth	0.519***	0.515***	0.516***	0.559***
	(0.113)	(0.122)	(0.121)	(0.111)
Depth^2	-0.024***	-0.024***	-0.024***	-0.027***
	(0.007)	(0.007)	(0.007)	(0.007)
Depth^3	0.0004**	0.0004*	0.0004**	0.0004**
	(0.0001)	(0.0001)	(0.0001)	(0.0001)
TVD	0.021	-0.0003	-0.004	-0.001
	(0.028)	(0.025)	(0.025)	(0.025)
Temp	0.005**	0.005**	0.005**	0.005**
	(0.002)	(0.002)	(0.002)	(0.002)
Temp^2	0.0001	0.0001	0.0001	0.0001
	(0.0001)	(0.0001)	(0.0001)	(0.0001)
Wind	-0.204***	-0.200***	-0.201***	-0.191***
	(0.041)	(0.040)	(0.040)	(0.039)
Wind^2	0.024***	0.023***	0.023***	0.022***
	(0.005)	(0.005)	(0.005)	(0.004)
Rig FE	Yes	Yes	Yes	Yes
Operator FE	No	Yes	Yes	Yes
Dir. Co. FE	No	No	Yes	Yes
Field FE	Yes	Yes	Yes	Yes
Year-Qtr FE	Yes	Yes	Yes	Yes
Observations	4404	4404	4404	4404

†, *, **, *** denote significance at the 10%, 5%, 1%, and 0.1% levels. Parentheses show robust standard errors clustered on field. Clustering on rig, operator, directional company, or year-quarter has little effect on the magnitude or significance coefficient estimates. Additional control variables are month of year dummies, a dummy variable for whether a spud rig was used divided by the well's depth, and a dummy indicating if the well was drilled into the Bakken or Three Forks formation.

7 Learning and Forgetting

In this section, I explore how organizational forgetting by rigs affects the speed in which wells are drilled. Organizational forgetting occurs when a firm's stock of experience declines, for reasons such as employee turnover, layoffs, literal forgetting by workers, or production interruptions.[7] Forgetting has been observed by Argote et al. (1990) in shipbuilding, Benkard (2000) in aircraft production, and others.

Rigs must be disassembled at one well location, transported, and reassembled at another drilling site. Thus breaks in drilling are unavoidable but cyclical and seasonal drivers will create variation in the lengths of these interruptions. The boom and bust nature of the oil and gas industry lends itself to studying the effects of organizational forgetting. Gyrations in oil prices and discoveries of new reserves cause drilling activity to ebb and flow. Moreover, in North Dakota, drilling activity follows a seasonal pattern that peaks in the summer and falls in the cold winter months. These fluctuations in drilling activity create variability in the duration between when a rig finishes drilling one well and begins the next. To determine the effect of interruptions in drilling, I estimate Equation 2, which supplements Equation 1 with a variable measuring the natural log of the number of days a rig was inactive prior to drilling a well.

$$LnRate_{rodft} = \gamma LnBreak_{rt} + \alpha_0 LnE_{rt} + \alpha_1 LnE_{oft} + \alpha_2 LnE_{dft} + \alpha_3 LnE_{ft} + \beta X_{rodft} + \phi_r + \psi_o + \zeta_d + \kappa_f + \lambda_t + \epsilon_{rodft} \quad (2)$$

$Rate_{roft}$ is the depth (in thousand feet) divided by days spent drilling the well drilled by rig r, operator o, and directional company d in field f at date t. $LnBreak_{rt}$ is the natural log of the number of days between when a rig finished the last well and began drilling the

[7]Benkard (2000) notes that the term forgetting is "somewhat inappropriate" because it encompasses several mechanism, such as employee turnover and layoffs, where no one is actually forgetting. A more accurate term may be depreciation of experience.

current well, and if the sign of the coefficient γ is negative it suggests that longer breaks diminish the benefits of learning.

The break variable in Equation 2 is potentially endogenous. That is, the length of time between when a rig finishes one well and begins drilling another may be correlated with unobservables that affect drilling speeds. This endogeneity may arise if there is a serially correlated shock to the rate in which a rig drills a well and this shock affects the duration of the break between finishing one well and beginning the next well. An example of this could be time-varying quality of the rig superintendent. A rig with poor management may take longer to drill wells, and it also may be in less demand and have longer breaks in between drilling; if this is time-varying, it cannot be accounted by inclusion of a rig fixed effect. This will bias the coefficient for $LnBreak_{rt}$ downward (away from zero). To deal with this issue, I exploit both the cyclical and seasonal variation in drilling activity within the Bakken. Greater demand for rigs in the Bakken is expected to reduce the duration of a particular rig's break in between drilling wells. Oil prices are likely a major determinant of the level of rig demand and in turn how long a rig waits to drill the next well. Rigs in the Bakken are also used to drill wells outside of North Dakota. Thus, greater drilling activity outside of North Dakota may pull rigs away and increase the duration of the break between finishing one Bakken well and drilling the next one.[8] A final source of variation in breaks is the seasonal pattern of drilling in North Dakota, which peaks in the summer months and declines in the winter months.

I instrument for the variable $LnBreak_{rt}$ with the average West Texas Intermediate (WTI) oil price and the average continental U.S. rig count (excluding North Dakota) observed during the quarter in which a rig last finished drilling, as well as the interaction of these two variables. Additionally, I include the year-month in which the rig last finished drilling to capture seasonality and allow the effects of seasonality to vary over the sample period. Given

[8]This analysis of forgetting does not account for wells drilled by rigs outside of the Bakken. Learning is assumed to be Bakken-specific, so that experience acquired in other basins is not transferable to wells drilled in the Bakken.

the boom in activity observed over 2005 to 2014, it is not unreasonable to expect that the seasonal pattern of drilling varies over time. The month of year in which a well was spud, the average ambient temperature, and the average maximum wind speed during drilling are included in Equation 2 to account for seasonal factors influencing drilling speeds. Thus, the year-month dummy variables for when a rig last finished drilling in the IV regression will not be correlated with unobserved seasonal drivers of drilling speeds.

The regression results for Equation 2, with and without the variable $LnBreak_{rt}$ instrumented, are presented in Table 3, along with the results of Equation 1 for reference. The coefficient for the logged break in drilling by the rig is -0.020 and significant at the 0.1% level. When instrumenting for a rig's break, the coefficient for the logged break in drilling by the rig is -0.015 and significant at the 5% level, implying that a doubling of the break in drilling leads to a 1.5% increase in days required to drill a well. The estimate is slightly smaller than the coefficients estimate of -0.020 in the uninstrumented model. This result is consistent with the aforementioned rationale for using an IV model: a serial correlated negative shock to drilling speeds that also increases the duration of a rig's break will bias the coefficient for $LnBreak_{rt}$ downward (away from zero). The results of the first stage regression show no evidence of weak instruments or underidentification.[9] The coefficients for the rig experience and operator-field variables are significant at the 0.1% and 1% levels, respectively, although the magnitudes of the coefficients are smaller.

The coefficients for logged rig experience and operator-field experience variables are 0.050 and 0.019, respectively. Using the sample mean number of 26 days required to drill a well (Table 1), these estimates translate to a reduction in drilling time of 1.3 days and 0.5 days. With an assumed rig cost of $24,000 per day (RigData, 2012), a doubling of rig decreases the cost by approximately $31,000, and a doubling of operator experience within a field reduces

[9]The first stage regresses the $lnBreak_{rt}$ on the quarterly oil price, quarterly rig count for Continental U.S. (excluding North Dakota), interaction of these variables, and the year-month dummies for when the rig last finished drilling, experience variables, other control variables, and dummy variables for rig, operator, directional company, field, spud month, and spud year-quarter. Overall, the coefficients for the instrumental variables are highly significant. The F-statistic for excluded instruments is 21.08, and the Cragg-Donald Wald F statistic for weak identification is 34.87.

Table 3: Regression Results- Forgetting

	Equation 1	Forgetting Equation 2	Forgetting IV
Regressor	*LnRate*	*LnRate*	*LnRate*
LnBreak_{rt}		-0.020***	-0.015*
		(0.005)	(0.006)
LnE_{rt}	0.074***	0.048***	0.050***
	(0.011)	(0.018)	(0.014)
LnE_{oft}	0.022**	0.019**	0.019*
	(0.008)	(0.008)	(0.008)
LnE_{dft}	0.009	0.009	0.009
	(0.008)	(0.008)	(0.008)
LnE_{ft}	-0.020	-0.020	-0.019
	(0.015)	(0.015)	(0.014)
Controls	Yes	Yes	Yes
Rig FE	Yes	Yes	Yes
Operator FE	Yes	Yes	Yes
Dir. Co. FE	Yes	Yes	Yes
Field FE	Yes	Yes	Yes
Year-Qtr FE	Yes	Yes	Yes
Observations	4404	4097	4053

†, *, **, *** denote significance at the 10%, 5%, 1%, and 0.1% levels.

costs by $12,000.[10] Over my sample period, a rig drills about 8 wells per year on average. This would imply that over the course of a rig's first year of drilling, learning by the rig alone results in a 11% decrease its time to drill a well.[11] If a rig took 26 days to drill a well at the start of the year, it would have reduced drilling time to 23.4 days/well or decreased its costs by $62,400/well by the end of its first year.

[10] 26 days $*$ 5.0% = 1.3 days and 26 days $*$ 1.9% = 0.5 days. $24,000/day $*$ 1.3 days = $31,200 and $24,000/day $*$ 0.50 days = $12,000.

[11] Drilling rate (y) can be written as function of experience (x): $y(x) = Ax^{0.05}$ and the 11% increase that results from increasing experience from 1 well to 8 wells is calculated as $y(8)/y(1) - 1 = (8/1)^{0.05} - 1 = 0.11$

8 Learning Spillovers

There is evidence of spillovers in semiconductor manufacturing (Irwin and Klenow, 1994), aircraft production (Benkard, 2000), and agriculture Conley and Udry (2010). In drilling, spillovers may occur as an operator drills wells within a particular area, acquires knowledge of its geologic formations, and this information spreads to other operators. Additionally, the mechanisms at work may be similar to those mentioned in urban agglomeration literature, where knowledge diffuses among workers employed in a dense area or ideas spread among firm management (Glaeser and Resseger, 2010). Drilling activity is relatively dense in Bakken, both spatially and temporally. The low permeability and porosity of the Bakken reservoir rock requires wells to be drilled closer to one another compared to conventional plays, and steep rates of production decline require new wells to be drilled frequently.

Typically an aggregate experience variable is used to measure learning spillovers. If the aggregate experience of all firms affects one firm's unit cost or productivity, when controlling for that firm's own level of experience, this suggests the benefits of learning spread to other firms. The results of Equation 1 (Table 2) show the coefficient on the field experience variable is statistically indistinguishable from zero at any reasonable significance level, implying there are not learning spillovers within a field. It may be the case, however, that learning spillovers are restricted to a small area nearby a well rather than an entire field. Wells being drilled within the same field in the Bakken can be 15-20 miles apart or more, and it is conceivable that experience gained in drilling wells at one end of a field may not be relevant to drilling wells at the other end of a field.

Operators typically use "offset wells" that are nearby a proposed well to serve as a guide in planning and designing.[12] In reports filed with the NDIC, operators occasionally list the offset wells used in planning a well. A brief, and by no means comprehensive, examination

[12]The Schlumberger oil field glossary defines an offset well as "An existing wellbore close to a proposed well that provides information for planning the proposed well. In planning development wells, there are usually numerous offsets, so a great deal is known about the subsurface geology and pressure regimes." (Schlumberger, 2015)

of these reports shows that the listed offset wells are often within a few miles of the planned well and may or may not have been drilled by the same operator. To investigate the presence of spillovers, I supplement Equation 1 with two additional experience variables: the logged experience of all firms within a 3 mile radius of a well's location and the logged experience of the well's operator within a 3 mile radius of the well. I change the radius to 1 mile and 5 miles to check robustness.

$$
\begin{aligned}
LnRate_{rodft} = {} & \delta_0 LnERad_{rodft} + \delta_1 LnEOpRad_{rodft} + \\
& \alpha_0 LnE_{rt} + \alpha_1 LnE_{oft} + \alpha_2 LnE_{dft} + \alpha_3 LnE_{ft} + \\
& \beta X_{rodft} + \phi_r + \psi_o + \zeta_d + \kappa_f + \lambda_t + \epsilon_{rodft} \qquad (3)
\end{aligned}
$$

As in the prior equations, $Rate_{roft}$ is the depth (in thousand feet) divided by days spent drilling the well drilled by rig r, operator o, and directional company d in field f at date t. $LnERad_{rodft}$ is the aggregate experience of all firms within a 3 mile radius of the well drilled by rig r, operator o, and directional company d in field f at date t, and $LnEOpRad_{rodft}$ is the experience of the operator o within that same 3 mile radius. The former of these variables measures spillovers. As in the other regressions, experience is measured by the cumulative number of wells drilled.

The regression results for Equation 3 with radii of 1, 3, and 5 miles are presented in Table 4, along with the results of Equation 1 for reference. For all models, the coefficient for the variable $LnERad_{rodft}$ is statistically indistinguishable from zero at any reasonable significance level. Thus there is no evidence for learning spillovers. The coefficients for the variable $LnEOpRad_{rodft}$, operator experience within a radius of the well, is positive and statistically significant in all three specifications. The coefficient for the operator-field experience variable shifts toward zero in the spillover models and is statistically significant at the 10% level in only the specification with a 1 mile radius. This suggests that learning

Table 4: Regression Results- Learning Spillovers

	Equation 1	Spillovers 3 mile Radius	Spillovers 1 mile Radius	Spillovers 5 mile Radius
Regressor	*LnRate*	*LnRate*	*LnRate*	*LnRate*
$LnERad_{rdt}$		0.014	-0.017	0.005
		(0.014)	(0.014)	(0.016)
$LnEOpRad_{rodt}$		0.026*	0.031*	0.034***
		(0.011)	(0.014)	(0.010)
$\text{Ln}E_{rt}$	0.074***	0.069***	0.070***	0.070***
	(0.011)	(0.012)	(0.012)	(0.012)
$\text{Ln}E_{oft}$	0.021**	0.004	0.015†	-0.001
	(0.008)	(0.009)	(0.008)	(0.009)
$\text{Ln}E_{dft}$	0.002	0.002	0.002	0.002
	(0.008)	(0.007)	(0.008)	(0.007)
$\text{Ln}E_{ft}$	-0.009	-0.015	-0.007	-0.012
	(0.013)	(0.015)	(0.014)	(0.016)
Controls	Yes	Yes	Yes	Yes
Rig FE	Yes	Yes	Yes	Yes
Operator FE	Yes	Yes	Yes	Yes
Dir. Co. FE	Yes	Yes	Yes	Yes
Field FE	Yes	Yes	Yes	Yes
Year-Qtr FE	Yes	Yes	Yes	Yes
Observations	4404	4404	4404	4404

†, *, **, *** denote significance at the 10%, 5%, 1%, and 0.1% levels.

occurs as an operator gains experience in a particular area within a field. The coefficient for the rig experience variable remains fairly consistent across specifications.

I hypothesize two reasons why there is no evidence for spillovers at either the field level or within the immediate area around a well. First, operators may effective at preventing information from spreading to other firms. Information regarding a well is considered to be highly valuable in the oil and gas industry and steps are taken to guard valuable data (Cathey, 2014; Eaton, 2014). However, spillovers are observed in other industries with arguably equally valuable trade secrets. Second, operators may mitigate spillovers by leasing acreage adjacent to a well and capturing the full benefits of learning. If an operator evaluates a particular field or section of a field as economically attractive, it may lease much of the surrounding acreage, which in turn diminishes spillovers.

This result suggests that operators do not externalize knowledge acquired through drilling wells that is relevant for improving drilling productivity. That is, as an operator gains experience drilling wells in a particular area, it internalizes the knowledge gained that useful in reducing drilling times for subsequent wells. This finding does not support the argument that subsidies to oil and gas companies are justified by positive externalities generated during drilling. However, it does not rule out the potential for other information spillovers to occur in oil and gas drilling. Other information acquired in drilling, such as the oil and gas resource potential of a particular area, is not considered in this paper and be may be externalized by operators.

9 Conclusion

This paper investigated the role of learning-by-doing in improving drilling productivity within the Bakken. It is the first to study learning-by-doing in horizontal wells within a tight-oil play, which are increasingly important source of global oil and gas production. Furthermore, this paper evaluates learning in a booming and dense production environment, which gives the potential for learning spillovers. The results of have implications for whether drilling activity in tight oil plays can continue in the current low-price environment, which in turn has ramifications for the future of U.S. oil production and job growth in the oil and gas sector.

I find evidence that drilling productivity increases as rigs gain experience in drilling wells and as operators gain experience within a field. With every doubling of rig experience, the time required to drill a well decreases by 5.0%, which translates to a cost savings of about $31,000 for a typical well. On average a rig drills 8 wells per year, which implies that in a rig's first year of drilling, it reduces drilling time and costs by 11%. In subsequent years, the decline in drilling cost is less dramatic as the rig's learning curve levels out. A doubling of an operator's experience within a field, decreases drilling time by 1.9%, which is about a $12,000 reduction in cost. These learning rates can help explain why drilling activity has appeared somewhat resilient to the steep oil price decline.

The results show evidence of organizational forgetting due to breaks in drilling. A doubling of the duration of a rig's break increases the days required to drill the next well by 1.5%. As drilling in the U.S. slows, rigs will be idled. This work suggests that once activity picks up again, breaks in drilling will negatively effect the time and cost to drill a well. Lastly, I find no evidence for learning spillover across firms, implying that firms do not externalize knowledge acquired through that is relevant to drilling productivity. I hypothesize that the lack of spillovers may occur because firms are effective at guarding valuable information or apply strategies for leasing acreage that allow them to reduce potential spillovers.

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Appendix

Table 5 shows the regression results for Equation 1 when wildcat wells are included, rig and directional company experience is dropped, and operator-rig experience is included. Wildcat wells are excluded from the results in the body of this paper because they do not have an identified field. Including wildcat wells has little impact on the results. As noted in Section 3, about one thousand observations are excluded because either the well's rig or directional drilling company cannot be identified. The column titled "Operator & Field Experience Only" includes these observations by excluding rig and directional company experience variables and fixed effects. The coefficients for the remaining experience variables are not affected by dropping these observations. The final column includes a variable of joint operator-rig experience. The coefficients for this variable is not statistically distinguishable from zero at any reasonable significance level.

Table 6 presents the regression results for Equation 1 with three different measures of experience. The first column is identical to "Equation 1" column of Table 2, where experience is measured by cumulative number of wells drilled. The second column uses the cumulative amount of feet drilled as the experience variable. In the third column, experience is measured as the number of wells drilled in the last two years; this setup assumes that wells drilled beyond two years ago are not relevant experience.

Table 7 summarizes distribution of operator, rig, directional company, and field pairing. That is, it shows the summary statistics for the number of fields per directional company, operators per directional company, etc. Overall, a given firm appears to work with multiple firms and in several fields, which mitigates potential collinearity of experience variables.

Table 5: Regression Results: Robustness Checks

	Equation 1	Include Wildcat Wells	Operator & Field Experience Only	All Experience Variables	Relationship Learning
Regressor	*LnRate*	*LnRate*	*LnRate*	*LnRate*	*LnRate*
LnE_{rt}	0.072***	0.078***		0.070***	0.061***
	(0.011)	(0.012)		(0.011)	(0.014)
LnE_{oft}	0.021**	0.023**	0.023**	$0.016^{\dagger}$	0.020*
	(0.008)	(0.008)	(0.009)	(0.009)	(0.008)
LnE_{dft}	0.002	-0.001		(0.001)	0.002
	(0.008)	(0.008)		(0.009)	(0.008)
LnE_{ft}	-0.009	-0.009	-0.012	-0.006	-0.009
	(0.013)	(0.013)	(0.014)	(0.013)	(0.014)
LnE_{rft}				0.010	
				(0.012)	
LnE_{ot}				-0.002	
				(0.022)	
LnE_{dt}				-0.034	
				(0.022)	
LnE_{rot}					0.013
					(0.013)
Depth	0.559***	0.511***	0.624***	0.549***	0.561***
	(0.111)	(0.114)	(0.134)	(0.111)	(0.110)
Depth^2	-0.027***	-0.024***	-0.032***	-0.026***	-0.027***
	(0.007)	(0.007)	(0.008)	(0.007)	(0.007)
Depth^3	0.0004**	0.0004**	0.0005**	0.0004**	0.0004**
	(0.0001)	(0.0001)	(0.0002)	(0.0001)	(0.0001)
TVD	-0.001	-0.020	-0.022	-0.002	-0.002
	(0.025)	(0.015)	(0.015)	(0.025)	(0.024)
Temp	0.005**	0.005**	0.006***	0.005**	0.004**
	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)
Temp^2	0.0001	0.0001	0.0003**	0.0001	0.0001
	(0.0001)	(0.0001)	(0.0001)	(0.001)	(0.0001)
Wind	-0.191***	-0.193***	-0.175***	-0.191***	-0.192***
	(0.039)	(0.037)	(0.0047)	(0.039)	(0.039)
Wind^2	0.022***	0.022***	0.020***	0.022***	0.022***
	(0.004)	(0.004)	(0.006)	(0.004)	(0.004)
Rig FE	Yes	Yes	No	Yes	Yes
Operator FE	Yes	Yes	Yes	Yes	Yes
Dir. Co. FE	Yes	No	Yes	Yes	Yes
Field FE	Yes	Yes	Yes	Yes	Yes
Year-Qtr FE	Yes	Yes	Yes	Yes	Yes
Observations	4404	4647	5229	4404	4404

†, *, **, *** denote significance at the 10%, 5%, 1%, and 0.1% levels. Parentheses show robust standard errors clustered on field. Additional control variables are month of year dummies, a dummy variable for whether a spud rig was used divided by the well's depth, and a dummy indicating if the well was drilled into the Bakken or Three Forks formation.

Table 6: Regression Results: Alternative Measures of Experience

	Experience-Cumulative Wells Drilled	Experience-Cumulative Depth Drilled	Experience-Wells Drilled Last 2yrs
Regressor	*LnRate*	*LnRate*	*LnRate*
LnE_{rt}	0.072***	0.075***	0.065***
	(0.011)	(0.011)	(0.009)
LnE_{oft}	0.021**	0.020*	0.018*
	(0.008)	(0.008)	(0.008)
LnE_{dft}	0.002	0.002	-0.001
	(0.008)	(0.008)	(0.009)
LnE_{ft}	-0.009	-0.009	-0.004
	(0.013)	(0.013)	(0.012)
Depth	0.559***	0.560***	0.552***
	(0.111)	(0.111)	(0.113)
Depth^2	-0.027***	-0.027***	-0.026***
	(0.007)	(0.007)	(0.007)
Depth^3	0.0004**	0.0004**	0.0004**
	(0.0001)	(0.0001)	(0.0001)
TVD	-0.001	-0.001	-0.001
	(0.025)	(0.025)	(0.025)
Temp	0.005***	0.005**	0.004**
	(0.002)	(0.002)	(0.002)
Temp^2	0.0001	0.0001	0.0001
	(0.0001)	(0.0001)	(0.0001)
Wind	-0.191***	-0.191***	-0.187***
	(0.039)	(0.039)	(0.039)
Wind^2	0.022***	0.022***	0.022***
	(0.004)	(0.004)	(0.004)
Rig FE	Yes	Yes	Yes
Operator FE	Yes	Yes	Yes
Dir. Co. FE	Yes	Yes	Yes
Field FE	Yes	Yes	Yes
Year FE	Yes	Yes	Yes
Observations	4404	4404	4404

†, *, **, *** denote significance at the 10%, 5%, 1%, and 0.1% levels. Parentheses show robust standard errors clustered on field.

Table 7: Summary Statistics for Distribution of Firm and Field Pairings

	Mean	Median	Std. Dev.	p25	p75	Min.	Max.
# of Fields per Dir. Co.	99	118	54	49	164	1	164
# of Operators per Dir. Co.	21	29	10	12	29	1	32
# of Rigs per Dir. Co.	77	83	47	29	136	1	136
# of Dir. Cos. per Field	7	6	3	4	10	1	13
# of Operators per Field	4	4	3	2	6	1	13
# of Rigs per Field	17	12	13	7	23	1	44
# of Dir. Cos. per Operator	10	8	5	7	12	1	21
# of Fields per Operator	31	23	21	18	40	1	82
# of Rigs per Operator	23	26	12	14	34	1	43
# of Dir. Cos. per Rig	3	2	1	2	4	1	8
# of Fields per Rig	7	7	4	4	11	1	18
# of Operators per Rig	2	2	1	1	2	1	6

2005-2014 sample period, 4,404 observations, 313 rigs, 62 operators, 44 directional companies, 269 fields