Drilling and Debt

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Abstract

This paper documents a new mechanism through which debt affects the real investment decisions of firms. Using detailed project level data in the oil and gas industry, we find that highly levered firms pull forward project completion at the expense of long run project returns and project value. This behavior is particularly pronounced prior to debt renegotiations. We test several channels that could explain this behavior and find evidence consistent with equity holders sacrificing long run project returns to enhance collateral.

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Understanding how debt affects a firm's investment decisions and real activities is one of the central questions in finance. Differing incentives of debt-holders and equity-holders have the potential to result in inefficient and value destroying decisions. Existing theoretical and empirical work has largely focused on the size, prevalence, and mitigation of investment distortions linked with the traditional agency costs of debt such as underinvestment and risk-shifting.[1] In this paper we document a new mechanism through which debt affects real investment activity and trace out how firm value is affected.

Using a novel empirical setting, we document that high leverage is associated with value destruction by equity-holders through a new mechanism linked with debt renegotiations. Specifically, we find that equity-holders distort the timing and composition of investment in ways that enhance collateral value prior to credit renegotiations. We show that these actions are at the expense of long run higher return and higher net present value (NPV) investment decisions. Our detailed data on project level cash flows and project NPVs under different alternatives faced by firms provides us with a unique ability to show that these actions destroy value.

Identifying how debt affects the actions of firms is empirically challenging. First, it is difficult to observe actions at the project or operational level, as well as how these actions might affect cash flows. Second, even if one can observe detailed actions by managers, assessing whether a decision is value maximizing requires a clear, unambiguous counterfactual decision of higher value to be observable. Lastly, leverage and the composition of credit agreements are not randomly assigned, and omitted endogenous variables could be related to both firm-level investment decisions and leverage, making it problematic to infer a causal relationship.

We focus on an empirical setting which allows us to make significant progress on each of these challenges. Specifically, we study detailed project-level completion decisions on North

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[1] Theoretical work focused on these issues includes Jensen and Meckling (1976), Myers (1977), Aghion and Bolton, (1992), Hart and Moore (1994, 1998), and Bolton and Scharfstein (1990, 1996). Empirical work includes Andrade and Kaplan (1998), Rauh (2009), Parrino and Weisbach (1999), Gormley and Matsa (2011), Eisdorfer (2008), Almeida et al (2011), Gilje (2016).

American shale oil drilling projects to explore how oil and gas companies with different levels of leverage react to the severe contango episode that began in December 2014. This setting has several advantages. First, we observe *project level* company decisions and can quantify the cash flow effect of completing an individual well versus delaying completion of said well. Our dataset contains detailed project-level data on 3,578 North American shale oil drilling projects. We know the date of well spudding (project start), well completion (first production and project cash flow), as well as the precise location of the well. These data allow us to control for potential heterogeneity in firms' investment opportunities.

Second, contango offers an attractive empirical setting as during this period spot oil prices are significantly lower than oil futures prices. Unlike most settings, because we can observe an oil futures price curve; we have a clear empirical counterfactual as to the expected value of delaying completion versus initiating completion of a project. In February 2015, for example, six-month oil futures prices were priced at an 11% premium relative to oil spot prices. In this environment, a decision to complete wells early and start producing oil is not value maximizing. This is in part because early production from shale oil projects is substantial, and then declines significantly each month, therefore pricing at the time of initial production is a key determinant of project level returns. We show that delaying production by 1 month / 3 months / 6 months would have enhanced an individual well NPV by 4.7% / 10.0% / 16.0% respectively.

Finally, the oil and gas industry is characterized by credit agreement renegotiation schedules that are defined in advance. Renegotiations are not a consequence of covenant violations, distress, or defaults, but rather a standard part of the debt contract lifecycle. Therefore, the timing of the credit renegotiations we study in our sample can be considered plausibly exogenous with respect to the oil price contango time period.

Our empirical design is constructed as a difference-in-differences estimation, where we compare project completion pre-contango versus contango of high leverage relative to low leverage firms. Specifically, we find that high leverage firms (those in the top 20% of the leverage distribution) on average start producing 1.1 months earlier during the contango time period, resulting in an estimated difference of 4.8% of the net present value (NPV) of a project or $124,000 per project. For the average firm, the aggregate effect across the projects we focus on in this study suggests that this behavior results in a 1.2% loss in equity value. This behavior is particularly pronounced prior to credit agreement renegotiation dates. In the month prior to a credit renegotiation or amendment, high leverage firms complete 145% more wells than they complete during the month following renegotiation. This figure compares to 63% for low leverage firms.[2]

The question remains as to the exact economic mechanism underlying the effect of debt and renegotiations on sample firms' investment decisions. The short-term transparent nature of the decision to accelerate production in relation to debt renegotiations eliminates a number of economic mechanisms capable of accounting for our results including risk-shifting, empire building, managerial reputation considerations, etc.[3] While all of these effects could drive investment decisions, it is unlikely that any of these would be linked with investment decisions in and around the precise timing of credit agreement negotiations. Therefore, we evaluate several hypotheses linked with different aspects of lending relationships.

First, we assess whether the decision to initiate production from wells early could be driven by liquidity or cash flow needs. We find evidence that it is not. Specifically, a firm in our sample has to incur, on average, $3.5 million in capital expenditures to complete a well producing at most $350,000 in EBITDA monthly for about 30 months. Therefore, a firm's short term liquidity position is adversely affected by the completion of a well, as the capital expenditure outlay is not recovered from cash flow for 10 months, at the earliest. Additionally, we collect detailed data on liquidity ratios and borrowing availability, and find that despite firms having high leverage, neither

[2] This result also helps rule out non-debt related explanations of our results. Firm leverage is endogeneous and it is possible that our results are due to some unobserved heterogeneity that is correlated with firm leverage, however, one would be unlikely to observe changes in project completion around debt renegotiations if a non-debt related explanation is driving our results. We also test explicitly whether heterogeneity in profitability, size, or market-to-book is associated with heterogeneity in well completion time, and find no evidence that they do.

[3] It is sufficient to delay completion by 3 to 6 months to capitalize on higher oil prices.

current ratios, interest coverage ratios, or credit facility availability indicate an impending liquidity crunch at the time of credit renegotiations.

Second, we explore the role that financial covenants may play in firms' decision to initiate production early from a well. We find no evidence that financial covenants contribute to our main result. We collect data on whether high leverage firms in our sample are in violation of any of their covenants during the time period of credit agreement renegotiations in the spring of 2015, and find that only one firm is in violation.

One can argue that while firms may not be in violation of a covenant, it could be that proximity to violating a covenant may be important. If this were the case one would expect that variation in well completion behavior would be linked to financial metrics such as interest coverage ratio. We find that high leverage firms with tighter interest coverage do not behave differently from high leverage firms with high interest coverage: both firm types are just as likely to pull forward completions. Furthermore, given that completing a well requires an incremental capital outlay, and financial covenant metrics are typically backward looking (current debt/trailing 12 month EBITDA), expending capital (funded by debt on the margin) to complete a well would adversely affect a firm's near term financial covenant metrics. Taken together, this evidence suggests that firms are not engaging in early completion of projects due to proximity to financial covenant violations.

Finally, we evaluate whether our findings could be driven by an effort by firms to increase or maintain the value of the collateral used to back their credit agreements. We find evidence consistent with the collateral based explanation by exploiting how cross-sectional heterogeneity in project type and geographic location affects collateral values assigned by banks. First, we evaluate whether high leverage firms initiate production on wells that produce more oil before debt renegotiation compared to wells opened after renegotiations. Since collateral is a function of the asset value which in turn is linked to the amount of oil a well produces, an effort to open more productive wells is consistent with an attempt to boost collateral values. We find that prior to debt renegotiations high leverage firms complete wells that have 43% higher daily production, relative to those completed by the same firms after debt renegotiations.

In addition, we exploit the heterogeneity in collateral values assigned to wells in different geographic locations. Initiation of new production has a different impact on collateral values for different oil leases. For example, completing a well and starting production on a lease that has no other operating wells has a greater collateral impact than completing a well on oil leases with producing wells. The geographic proximity to a new producing well(s) potentially reduces asymmetric information and allows lenders to assign higher collateral values to even non-producing assets. We find evidence that prior to credit agreement negotiations, firms are more likely to initiate production for wells on leases with no production.

Overall, our results suggest that debt renegotiations have the capacity to create negative investment distortions even before the potential reallocation control rights to debt-holders. Our evidence indicates that highly levered firms sacrifice 1.2% of equity value prior to credit renegotiations.[4] We estimate this action increases collateral value by 6.9%, relative to not starting production early. This finding highlights a novel mechanism through which debt effects the real actions and investment decisions of firms.

The primary contribution of our study is to provide a novel channel through which debt and debt renegotiations affect firms' real investment decisions. The extant incomplete contracting theoretical literature argues that debt renegotiations re-allocate control rights between debt and equity-holders in a state-contingent manner, and thus mitigate the adverse effect of incentive misalignment on firms' investment decisions. The empirical literature documents that covenant violations result in significant changes in firms' investments (Beneish and Press, 1993, 1995, Chen and Wei, 1993, Chava and Roberts, 2008, Roberts and Sufi, 2009a). Both streams of literature

[4] Note that the 1.2% equity value effect we identify is not necessarily sub-optimal from the equity holders' perspective, conditional on a firm having high leverage and needing to renegotiate with increased collateral. Rather, this value destruction could be viewed as being caused by the frictions associated with the aspects of the debt-equity relationship that require collateral as a component of lending contracts to begin with.

argue that covenants lead to Pareto improving reallocation of control rights and better investment outcomes.

We add to this literature by documenting that the potential threat of reallocation of control leads to adverse investment decisions by equity holders and destruction of equity value, and firm value, even before the renegotiations and in absence of covenant violations. Nini, Smith, and Sufi (2009) and Denis and Wang (2014) are the closest papers to ours. They show that debt contract restrictions/renegotiation are not only common features of financial contracts but also affect investments even when no covenant violations have occurred. These studies argue that debt restrictions are *value enhancing*.[5] In contrast we document mechanisms of lending relationships that can cause *value decreasing* actions by equity holders.[6]

Finally, our findings have implications in the literature exploring the violations of Hotteling (1931) in the oil market. The existing literature finds oil production to be price inelastic in the short run (Hamilton 2009; Kellogg 2011). Anderson et al. (2014) attribute the lack of production adjustment to price incentives to unique production technology in the oil industry that imposes significant costs on shutting and reopening traditional wells that yield oil for 10 to 20 years. New oil production technology (fracking) and the associated short-term nature of well lifecycles have led researchers to question the continued nature of inelastic oil production. However, studies have found that production has remained inelastic despite the new technology (Lehn and Zhu, 2016). Our results suggest that debt financing of the newly developed oil reserves creates significant frictions preventing downward adjustment in oil production when oil prices fall unexpectedly.

This paper proceeds in the following order. Section 2 discusses the data and institutional background that is used. Section 3 discusses our empirical design and results. Section 4 concludes.

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[5] Similar conclusions stem from Demiroglu and James (2007) who find that firms experiencing tighter financial covenants experience better operating and stock price performance.

[6] Our results also inform theoretical literature on incomplete contracting that explores the role of financial contingencies including Aghion and Bolton, (1992), Hart and Moore (1994, 1998), and Bolton and Scharfstein (1990, 1996). Our evidence indicates that in the presence of such financial restrictions, equity holders might adversely alter their investment to better their renegotiation position and deter reallocation of control rights.

2. Institutional Background and Data

The shale oil industry offers an attractive setting in which to examine the relationship between leverage and investment decisions. The presence of a futures curve for the price of project output provides firms (and econometricians) with an indication of the expected benefit associated with completing a well. Detailed project-level data indicates the precise timing of well completion, which allows us to observe the relationship between investment outlays and expected project benefits. The publicly available project-level data also contains information on well location and the timing of other important events in the oil extraction process, which allows us to control for a variety of alternative factors linked to investment opportunities. By matching the project-level data with firm characteristics, we can examine how the investment response to expected project value depends on firm leverage.

In this section we provide more detail on each individual component of our empirical setting. We first discuss the contango episode we exploit. We then offer a detailed discussion of fracking projects in Oil and Gas industry, describe the project-level data we utilize, and discuss how the exogenous contango episode affected the NPVs of individual fracking projects in our data.

2.1. Institutional Setting and Oil Price Contango

In this study we exploit the unique evolution of spot and futures prices in the oil market between November 2014 and June 2015. In late 2014, abrupt changes in the oil prices futures curve, due to the decision by OPEC not to support oil prices, dramatically affected the expected profits from completing new oil wells early versus waiting to complete the wells.

Between 2012 and the first half of 2014 spot oil prices hovered around $100 a barrel and were expected to fall below $90 based on oil futures contracts. The market was in backwardation: two-year futures contracts were priced between 10% and 20% lower than spot prices, reflecting an expected decline in spot prices. In late 2014 spot prices began a rapid decline through January of

2015 when the price reached below $50 a barrel. The decline was much larger than predicted by futures prices or other information in oil markets, reflecting a combination of demand and supply shocks in the global oil market (Baumeister and Kilian 2016b).

By the start of 2015 the oil market changed from backwardation to severe contango. In January the 2-year futures price exceeded the spot price by nearly ***30%*** (Figure 1). 6-month futures prices exceeded the spot price by over 10%, a drastic change from the backwardation in oil markets just two months prior. The 2015 futures curve exhibited dramatic deviation from spot prices across all maturities. Figure 2 compares the futures curve as of February 2015 to one as of September 2014. The 2015 contango was unprecedented as futures prices exceeded the spot price by more than three standard deviations relative to prior periods. The 2014-2015 contango was not only severe in terms of futures price deviation from the spot prices, it was also abnormally long extending through the rest of 2015. In April 2015 spot prices experienced a slight increase reaching $60, consistent with the upward price trajectory projected by futures prices as of the beginning of 2015. By mid-year, however, spot prices declined again and the market remained in strong contango through 2015 and into early 2016.

The exogenous severe contango episode of 2014-2015 played an important role in companies' assessment of future expected cash flows from fracking and oil production operations. Futures prices are traditionally used by both academic and practitioners alike as a good estimate of expected future oil prices. Kellogg (2014) prominently features this assumption under risk neutral traders and efficient aggregation of market information conditions. Consistent with the information content of oil futures in the post-recession era, most oil producers use futures prices in forming their expectations (Society of Petroleum Evaluation Engineers 1995).

Admittedly, whether the futures price provides a superior forecast (relative to the no-change forecast based on the current spot price) depends on the sample period (e.g., Chernenko et al 2004; Alquist and Kilian 2010). During the relevant post-Recession time frame of our study, out-of-sample forecasts using futures prices significantly outperform out-of-sample forecasts that disregard information in futures markets (see the application of the Hamilton and Wu (2014) model in Table 6 of Baumeister and Kilian (2016a)). We, therefore, follow Kellogg (2014) and equate the futures price with the expected future spot price of oil.

Under this assumption, normal market backwardation conditions create incentives for oil producers to accelerate oil production in the current period because spot prices exceed that of expected future prices. In contrast, during the severe contango episode, oil producers have a disincentive to initiate new production and bring new (fracking) operations online. Consistent with this argument, we exploit the sharp shift to contango in December 2014/January 2015 as an exogenous shock to U.S. producers' incentives to complete oil wells. In the absence of constraints, firms' incentives were to postpone production as the value of oil produced six months in the future was expected to be at least 10% higher than the value of oil produced in early 2015.

2.2. Shale Oil Drilling Overview

Before we discuss how the contango affected individual oil drilling, fracking, and production projects of U.S. oil and gas firms we would like to provide an overview of the current state of shale oil drilling operations. In 2003, a surprise technological breakthrough combined horizontal drilling with hydraulic fracturing ("fracking"), enabling development of natural gas shale. In 2009 the innovation extended into oil development and dramatically reshaped the U.S. oil industry. While prior to 2009 shale oil production contributed minimally to global oil supply, the technological change resulted in an increase of U.S. oil production from 5.4 million barrels/day in 2009 to 9.4 million barrels/day by the end of 2014. This increase represented 52% of the overall increase in oil production globally. Shale oil development has been one of the largest economic transformations that the U.S. economy has experienced, resulting in an aggregate increase of $2.5 trillion in U.S. equity market capitalization (Gilje, Ready, Roussanov 2016).

By early 2014, approximately 70 public oil and gas firms and more than 120 private firms were using fracking technology. In fact, by mid-2014 these companies were producing oil from over 200 thousand oil wells across five states with shale oil fracking operations: Texas, Oklahoma, North Dakota, Colorado, and New Mexico. On a 6 miles by 6 miles square, one can run as many as 288 individual oil wells (Figure 3).

Shale oil resides in geologic formations up to two miles below the earth's surface. To extract these reserves, firms first have to secure mineral rights from respective property owners. These *oil leases* allow energy companies to drill and then hydraulically frack shale formations to free oil from shale rock. Shale oil well drilling is somewhat unique relative to other types of oil extraction in that it requires two distinct project steps. First the well must be drilled, second the well must be hydraulically fracked. To complete the drilling stage, the majority of the firms in the industry rent a drilling rig from specialized service providers. It takes these service providers from 3 days to 3 weeks to spud and drill onshore wells and costs on average $3 to $3.5 million dollars.[7] The spudded well can sit idle until the company decides to complete or "frack" it.[8] The hydraulic fracturing process is separate from the drilling process and can occur any time after initial drilling has been completed. Once again it involves using a contractor that specializes in fracking (completing) wells. Firms that specialize in fracking include Halliburton, Baker Hughes, and Schlumberger. It typically takes two or three days to complete the fracturing process and costs about $3 million for an average well.

The production typically starts immediately after the well is completed (fracked) for a number of reasons. First, the completion specialist has to test the well and report the initial production volume and oil quality measurements to a respective regulatory body (e.g., Texas Railroad Commission for the state of Texas). Once the well is fracked disrupting the pressure in the well is prohibitively costly: the proppant used to frack the well begins to disintegrate immediately after a well is completed which reduces the amount of oil that can be recovered from a well. Every day not spent pumping is in essence a day of lost production and cash flows.

[7] Spudding involves drilling the well into the shale and inserting steel well casing and cement down the hole.
[8] Typically, oil lease contracts with mineral owners allow an oil producer to maintain their lease so long as drilling has started and a shut-in royalty of as little as $10 per month is paid to the mineral owner.

Once a well is completed, production typically declines quickly. High initial pressure leads to high initial production but as pressure is released from a well, the production quickly declines month over month. Consequently, oil prices at the beginning of a well's productive life are critical in determining the economic return of a well. Figure 4 illustrates the declining after-tax cash flow from production by an average well in North Dakota.

This declining production schedule plays an important role during the period of super-contango described above. In Figure 5 we illustrate the NPV of a decision to delay production by 1 month to 6 months using the production volume of a representative well.[9] In this example we exploit the average production profile of 2,484 wells in North Dakota in 2014. The futures curve used to project these cash flows is the average of the NYMEX futures curve during the contango period in our sample. This NPV calculation assumes a 10% discount rate.

The two-stage oil extraction process -- drilling/spudding and fracking/completing-- provides a number of empirical design benefits. First, we can isolate the decision to start production (complete a well) from that of exploratory drilling. Second, the ability to cap the well for an indefinite period of time after drilling but before the completion clearly isolates two operational decisions. The costs of drilling become a sunk cost at the time the completion/production decision is made (Kellogg, 2014). Finally, the inability of firms to delay the production after the well was completed and the need to report the completion date to the regulatory body provides us with a fairly precise date of the completion decision. We exploit all these features in building the sample of oil well projects for our analysis.

2.3. Well Project-Level Data.

Our sample selection process is based on the two stages of the oil development process. We start with the most comprehensive well drilling data set available, which is provided by

[9] Additional assumptions include average royalty rate is assumed to be 3/16, corporate taxes are assumed to be 38%, oil and gas severance tax is assumed to be 3%.

RigData, Inc. RigData relies on public filings and relationships with a wide set of drilling contractors to precisely track the start of every well drilling operation in the United States. Our study focuses on shale drilling in Texas, North Dakota, Oklahoma, New Mexico, and Colorado, states in which 98% of U.S. shale oil drilling has taken place.

While RigData, Inc. provides the date of the first stage of well development (drilling), it does not provide the well completion and start of production date. We augment the RigData by hand collecting the completion date from regulatory filings on well completion collected by the oil industry regulatory bodies in major shale oil producing states. These include the Texas Railroad Commission (form W-2), the Oklahoma Corporation Commission (form 1002A), the North Dakota Industrial Commission (form 6), New Mexico Department of Energy and Minerals (html web form), and the Colorado Oil and Gas Conservation Commission (html web form). We also cross check dates with completion information from fracfocus.org.

Our empirical strategy evaluates how contango affects the completion decisions made by individual firms. As such we need to isolate the completion decision from the drilling decision. In order to accomplish this goal, we focus on oil wells that were spud before the onset of contango, September 2014 through November 2014. We then evaluate the completion decisions for these wells during the severe contango period of December 2014 through March 2015. We further augment this sample and consider wells spud and potentially completed during the period of (more typical) backwardation. Specifically, we use wells spud in September 2013 through November 2013 and evaluate their completion decisions during December 2013 through March 2014 to benchmark firms' completion decisions. We intentionally maintain the same calendar month to eliminate any explanations stemming from seasonal variation in oil production.

Our main variable of interest is the time between the spud date of a well and the completion date. As reported in Panel A of Table 1 this variable exhibits significant heterogeneity in our sample. It can take from as little as one month. We also observe drilled wells sitting idle for in excess of two years before the production is commenced. Some wells in our sample were spud in late 2014 and are still not completed as of two years later. The median time between drilling and completion dates is 4 months.

We hand match individual project data on drilling and completion to a set of public oil and gas companies. Panel A of Table 1 reports core financial characteristics of the oil and gas companies in our sample including the core variable of interest in this study – market leverage. Panel B splits the sample into two sub-samples: high and low leverage firms. We define all firms in the top 20% of the market leverage distribution as of the end of 2014 as high leverage firms. The remainder of the sample we classify as low leverage firms. Panel B of Table 1 illustrates that high leverage firms are smaller and are characterized by lower Tobin's Q.

To address alternative explanations of our results (see discussion below) we further supplement the well project drilling and completion data with detailed information about the geographic location of the wells in our sample (land survey section township range or latitude and longitude) provided by the state regulatory bodies. This data allows us to control for well quality and investment opportunities as shale geologic qualities are similar over the 6 mile by 6 mile areas (townships) over which we conduct our comparisons. Furthermore, we collect additional well characteristics such as well completion costs and initial production volume. We obtain this data from regulatory reports where available.

Finally, we hand collect detailed information about public firms' credit line and debt contracts from SEC filings offered by EDGAR. Specifically, we focus on the size of the credit line offered by banks to firms in our sample, pre-set renegotiation dates, covenants and collateral constraints imposed by the debt agreement. This information is collected for the years leading up to and including the contango episode (2013 through 2016 financial reports).

3. Empirical Analysis and Results

In this study we exploit two empirical designs focused on the exogenous onset of the super-contango, which should incentivize firms to delay completion of their shale oil projects. Specifically, we implement two difference-in-differences (DiD) regression analyses. The first compares the well completion decisions of high and low leverage firms between 2014-2015 contango period and 2013-2014 backwardation period. This analysis allows us to evaluate whether, during the contango episode, high leverage firms complete wells quicker than low leverage firms. It also allows to confirm that contango creates a disincentive for (all) oil and gas firms to complete wells and start production

The second DiD analysis exploits pre-set renegotiation dates of credit agreement contracts. Specifically, we evaluate whether, during the contango episode, imminent debt renegotiation creates an incentive for high leverage firms to complete wells earlier, relative to low leverage firms. This analysis allows us to evaluate whether debt renegotiations play an important role in firms' decisions to accelerate oil productions.

3.1. Super-contango and Well Completion Decisions

The core analysis of this paper evaluates the timing of well completion by high and low leverage firms (first difference) by comparing their completion decision during the periods of contango and backwardation (second difference). Specifically, we focus on wells spud in September –November 2014 and measure whether their time of completion was affected by contango. We benchmark contango completions against the completion decisions of wells spud during September –November 2013 when markets were in backwardation. The 2013 sample serves as our baseline time period, and allows us to difference out operator specific differences in project completion time.

Table 2 presents the results of a univariate comparison of the time to completion decision across high and low leverage firms during periods of contango and backwardation. We find that low leverage oil producers, those in bottom four quintiles of the leverage distribution, behave as expected. They delay well completion during super-contango by about 1 month compared to well completion in 2013. The one month extension is statistically and economically significant as it constitutes about a third of the average completion time in 2013. In contrast, high leverage (top quintile) producers do not delay production. The lack of adjustment to completion time for high leverage firms is consistent with the notion that debt distorts firms' incentives.

One can argue that the results we document in Table 2 can be driven by other unobserved heterogeneity rather than financial constraints such as differences in investment project or growth opportunities. For example, high-leverage firms may choose to complete wells that require less capital or are more/less productive. Panel A of Table 3 confirms that important differences in project type exist across high and low leverage firms. We control for this heterogeneity in quality by using a set of 6×6 mile geographic fixed effects. Since differences in production capacity and costs of well completion are driven by characteristics of shale reservoirs, wells located at most within 8.5 miles $(6^2+6^2)^{1/2}$ away from each should not exhibit dramatic differences in these characteristics. Panel B of Table 3 illustrates the efficacy of 6×6 mile geographic fixed effects. For the subset of wells for which we have costs and initial production data, Panel B of Table 3 illustrates that geography and firm fixed effects explain vast majority of heterogeneity in well costs and production heterogeneity. Specifically, while the sub-samples of high and low leverage firms exhibit economically significant differences in well costs and production, these differences are fully eliminated in the regression setting that incorporates proposed fixed effects. Therefore, we implement regression analysis that examines the effect of contango on well completion times of high-versus-low leverage firms conditional on well location. Below is a regression form of our core difference-in-differences test. The unit of observation is well *j* of firm *i* at time *t.*

$$Time\ To\ Completion_{ijt} = \beta_1 Contango_t + \beta_2 HighLev_i \times Contango_t + \\ + Firm\ FE_i + Geography\ FE_k + \epsilon_{ijt}$$

where $Time\ To\ Completion_{ijt}$ is the number of months between the start of well j drilling and its first production day. $Contango_t$ is an indicator variable that equals unity for wells spud in late 2014, the period just prior to the emergence of contango in the oil market. Time *t* is either the contango year (2014) or the backwardation year (2013). $HighLev_i$ is an indicator variable for whether the firm is in the top quintile of the leverage distribution. $Firm\ FE_i$ and $Geography\ FE_k$

are firm and geography (township level) fixed effects. The key coefficient of interest is the coefficient β_2 on the interaction term $Contango_t \times HighLev_i$ which indicates whether high leverage firms initiate production on their wells sooner than low leverage firms during the super-contango period relative to the baseline period.

Table 4 reports the results controlling for geography and operator fixed effects. We find that in contango, firms in all but the top quintile of the leverage distribution delay well completion by 1.07 months. Column 1 demonstrates the nonlinear dependence of wait times during contango on leverage. Firms in the top quintile, however, pull forward completion relative to their less constrained peers. The difference in completion times is even more pronounced when examining firms with high leverage and asset based lending (column 3). The results are nearly identical when using the natural log of completion time rather than the level (columns 4 through 6 of Table 4).

The lack of a completion time response for high leverage firms is consistent with the notion that debt distorts firms' incentives. Based on the representative well-level cash flows presented in Figure 4, we estimate that by not expanding time to completion by one month, high leverage firms are foregoing 4.8% of project NPV or $124,000 per project. The number is economically significant. Considering the number of projects completed during the period of contango, acceleration of project completion by one month had the potential to destroy as much as 1.2% of equity value for high-leverage firms.

Alternative Explanations

One possible interpretation of the results in Tables 2 and 4 is that firm characteristics that are correlated with high leverage, rather than leverage itself, are responsible for the different responses to contango. Panel B of Table 1 shows that high and low leverage firms differ in terms of size and Market-to-Book, a proxy for investment opportunities. To rule out these explanations linked to observed heterogeneity, we augment the set of control variables with firm characteristics interacted with a contango dummy. Table 5 shows that heterogeneity in firms' size, profitability or Tobin's Q cannot explain out results. The evidence suggests that high leverage firms accelerate well completion by one month even after we control for these firm characteristics, allowing us to conclude that the differential response to contango is associated with high leverage rather than profitability, size, or market-to-book ratios.

The evidence presented in Tables 2, 4 and 5 uniformly suggest acceleration of production by high leverage firms relative to low leverage firms and supports the notion that debt distorts firms' investment decisions.

3.2. Debt Renegotiations

To further validate the notion that debt distorts firm investment decisions we evaluate completion decisions of high and low leverage firms around debt renegotiation dates. Specifically, in this section we exploit firms with asset based loans tied to the value of their oil reserves. These firms are uniquely suited for DiD analysis since the asset backed credit agreements are renegotiated about every 6 months on a defined-in-advanced schedule. Consequently, most Spring renegotiations of the credit agreements we exploit were pre-scheduled well before the onset of contango.

45 of our 69 firms in our sample have such agreements and did go through renegotiation of their asset based loans in February, March, April, or May of 2015. We hand identify and collect detailed data on their credit agreement including credit line size, utilization, renegotiation dates, covenants, and collateral constraints.

We aim to compare well completion decisions of high vs low leverage firms (first difference) around debt renegotiation dates (second difference). Yet in this setting evaluating the time to completion is counterproductive as for wells drilled in September through November of 2014 time to completion should increase purely mechanically from before negotiation to after renegotiation. To address this issue we slightly adapt our empirical design and measure production decisions in an on/off fashion. Specifically, our dependent variable $Well\ Starts\ Production_{ijt}$ takes the value of 1 if a well is turned on from idle to producing in a given month, and it is 0 in other months (if it was producing the prior month, and then continues to produce the value is 0).

The unit of observation is well *j*, firm *i*, month *t*. The new dependent variable can be interpreted as the change in new wells being added to production. Effectively, if one averages the dependent variable within each firm *i*, within each month *t*, one would estimate the share of firm *i* well in our sample that started producing in a given month. If debt renegotiations intensify the distortive effects of leverage on investment decisions we should observe high leverage firms complete a higher percentage of wells prior to debt renegotiations as compared to completion decisions of low leverage firms.

Table 6 reports the univariate analysis of completion decisions around renegotiation dates and compares such decisions for high and low leverage firms. We observe evidence consistent with distortive effects of debt. The estimate of 0.21 at time t-1 for high leverage firms suggests that one month prior to renegotiations high leverage firms complete 21% of wells they had started in the fall of 2014. This number drops to 8% in the month after renegotiations, a change that is both economically and statistically significant. In contrast low leverage firms exhibit a much smaller change in well completion percentages around the debt renegotiations dates.

We then confirm a similar pattern using regression analysis of the completion decisions relative to debt renegotiations in event time, where we control for geography, firm and month fixed effects. We use the following regression specification:

$$Well\ Starts\ Production_{ijt} = \sum_{m=-3}^{3} \alpha_{\mathrm{m}}\ Reneg\ Month_{j,i,m,t} +$$

$$+ \sum_{m=-3}^{3} \beta_{\mathrm{m}}\ Reneg\ Month_{j,i,m} \times HighLev_i + FirmFE_i + GeogFE_k + Month_t + \epsilon_{ijt}$$

where $Month\ Dummy_{j,i,m,t}$ is equal to 1 if well *j* of firm *i* starts production in month *t* and this month is *m* month removed from the month of credit agreement renegotiation, and zero otherwise. For example, if firm *i* has a credit renegotiation in March of 2015 and well j starts is completed in April 2015 then $Month\ Dummy_{j,i,1,April} = 1$ and $Month\ Dummy_{j,i,1,March} = 0$. β_{m} are the key coefficients of interest. Specifically, if debt renegotiations intensify the distortive effects of leverage on investment decisions we high expect firms to complete more well just prior to debt renegotiations (*m=-1* or *m=-2*) than after the renegotiation decisions (*m=1* or *m=2*).

The regression analysis results reported in Table 7 are similar to the univariate analysis reported in Table 6. Column (1) of Table 7 documents that between m= -1 and m = 0, the share of completed wells drops by 11.3% (–0.135 – 0.022). This is similar in magnitude to the 0.12 change in completion rate documented in Table 6. In contrast the number of new wells being brought on line by the low leverage firms (column 2) does not vary across debt renegotiation dates in a statistically or economically significant way.

To put these results in economic context, if a sample firm has 100 wells that it had drilled but not initiated production in the Fall of 2014 the average firm, as identified in Table 6, would have had 21 wells of the 100 begin production in $m = -1$ (note there may be some wells of the 100 already producing based on completions in $m = -2$ or earlier). This same firm would have had only 8 out of the 100 well completed in $m = -2$. Similarly, the regression coefficient of 0.113 can be interpreted as after the debt renegotiation an average firm bring on-line 11.3 out of the 100, fewer wells than in the month after renegotiation. Interestingly, after the controls and fixed effects are added there is almost no change in the implied economic magnitudes of the documented effects.

3.3. Debt Effect on Investment Decisions: Economic Channels

The results presented in Tables 2 through 7 uniformly indicate that high leverage distorts firm investment decisions. Yet the question remains as to the exact economic mechanism underlying the effect of debt and renegotiations on sample firms' investment decisions. The short-term transparent nature of the decision to accelerate production in relation to debt renegotiations eliminates a number of economic mechanisms capable of accounting for our results including risk-shifting, empire building, managerial reputation considerations, etc. While all of these effects could drive investment decisions, it is unlikely that any of these would be linked with investment decisions in and around the precise timing of credit agreement negotiations. Therefore, we evaluate several hypotheses linked with different aspects of lending relationships.

Liquidity Constraints

First, we assess whether the decision to complete wells early is driven by liquidity or cash flow needs. We find evidence that it is not. Panel A of Table 8 reports the debt and liquidity metrics of the high leverage firms in our sample. The high leverage firms in our sample have solid liquidity measures, with an average current ratio (Current Assets/Current Liabilities) of 2.464, and average interest coverage of 3.18, and on average these firms have drawn only 37.3% of their credit lines. The average firm in our sample has investment plans that are 106% of current cash flows, indicating significant potential funding needs. Indeed, these firms may not have the strongest balance sheets, yet they are not vulnerable to imminent default.

In addition, a firm in our sample has to incur, on average, $3.5 million in capital expenditures to complete a well producing at most $350,000 in EBITDA monthly for about 30 months (Figure 5). Therefore, a firm's short term liquidity position is adversely affected by the completion of a well, as the capital expenditure outlay is not recovered from cash flow for 10 months, on average. Additionally, we collect detailed data on liquidity ratios and borrowing availability, and find that despite firms having high leverage, neither current ratios, interest coverage ratios, or credit facility availability indicate an impending liquidity crunch at the time of credit renegotiations.

Covenant constraints

Second, we explore the role that financial covenants may play in firms' decision to initiate production early from a well. We find no evidence that concerns regarding financial covenants contribute to our main result. To evaluate this hypothesis we hand collect detailed data on credit agreements covenants for firms in our sample. Specifically, we evaluate whether our results are driven by high leverage firms being in close proximity of violating the covenants during spring 2015. We find that only one firm in our sample was in violation of its covenants. The credit agreement of this firm was amended before credit renegotiation and a covenant "vacation" was announced by the lender. The rest of the sample firms exhibited financial characteristics that left sufficient margin relative to imposed covenant constraints.

We implement DiD regression analysis around renegotiation dates and compare the results for firms with high and low interest coverage ratio, a widely used covenant measure. In Panel B of Table 8 we explicitly test whether high leverage firms with high and low interest coverage initiate production on wells differently. If anything, we find that firms with better interest coverage reduce their completions more. In column (2) the share of completed well declines by 17% (-0.101 - 0.069) from the pre renegotiation month to post renegotiation month ($m=-1$ to $m=0$). In contrast, firms with lower interest coverage, column (1), show only 9% decline (-0.169 – (-0.079)) over the sample period. This result is inconsistent with a financial covenant based explanation.

Finally, it is important to note that many financial covenants are backward looking and also could be adversely affected by completing a well early. For example, firms with debt/EBITDA covenants would suffer a worse covenant metric if they completed a well as well completion will be funded at the margin by additional debt. The effect would be magnified by the fact that the debt balance would be affected immediately, while trailing 12-month EBITDA would only see a marginal increase. Taken together, this evidence suggests that financial covenants are not the primary driver of our results.

Collateral Constraints

Finally, we evaluate whether our results are driven by firms attempt/need to signal to banks the quality of their assets, cash flows, and collateral by bringing on-line production, even when they have an economic incentive not to. Higher expected future cash flows, for example, can increase collateral values and improve firms' ability to secure more and cheaper credit. Specifically, increases in production and well completion affects the borrowing base in credit agreements. Borrowing base is the collateral value lenders ascribe to a borrowing firm's producing wells, non-producing/drilled wells. The borrowing base is adjusted up when new wells are drilled, better wells are drilled, or commodity prices increase. The borrowing base is adjusted down if wells are depleted, bad wells are drilled, or commodity prices decline. The borrowing base determines the borrowing limit on credit agreements.

To evaluate the collateral hypothesis we first compare the quality of wells completed right before a debt renegotiation versus those completed right after. Univariate analysis presented in Table 9 shows that wells completed just prior to a credit renegotiation have higher initial production than wells completed after renegotiation. Specifically, prior to debt renegotiations firms initiate production on wells that produce 417 barrels per day, versus 292 barrels per day right after debt renegotiations. High production allows firms to signal the quality of reserves and allows borrowers to increase their borrowing base.

Apart from directly affecting the collateral value of completed wells, production decisions have the capacity to increase collateral values assigned to the undeveloped resources. Proved production capacity increases collateral values of drilled and prospective wells in the proximity of the newly completed production operation. We exploit this heterogeneity in our last set of tests reported in Table 10.

We divide drilled wells into two groups based on their ability to affect collateral values of all wells in a given oil lease. Some wells are the first well on a lease, when a firm initiates production on these wells; it gets collateral credit for turning on the well, but also enhances the value assigned to other prospective undrilled wells within the same lease. We consider these wells high collateral impact. Other drilled wells are located within close proximity of already producing wells (within the same lease). Completing these wells, all else equal, would increase collateral value for just the well that production starts on, but is unlikely to affect the collateral values assigned to undeveloped resources within the same oil lease. We split our sample wells based on these well definitions in Table 10 and find that nearly the entire effect we identify in Table 6 is due to high collateral impact wells. Table 10 offers further evidence towards a collateral channel.

So what do firms get for completing their best wells early to generate collateral value? Banks ascribe significantly more collateral value to producing reserves. We estimate that on average, firms increase their available collateral by 6.9% due to bringing new production on-line early. This figure is based on the average NPV for completing wells in our sample, and banks ascribing the industry standard 50% lending capacity for well NPV.

4. Conclusion

In this paper we test a new dimension along which debt may induce firms to pursue lower project level returns. We find that anticipated credit renegotiations are an important consideration in how firms pursue investment decisions and operational actions. High leverage firms, in particular, are vulnerable to pulling forward project completion to enhance near term cash flow at the expense of long run project level returns. Equity holders forgo project level returns to enhance collateral value in exchange for greater credit availability. Ultimately, this cost is incurred due to the information asymmetry and moral hazard problems lenders face, and the need to use mechanisms such as collateral to mitigate these issues. Equity holders pay a portion of equity value to overcome this information asymmetry by initiating project cash flows early.

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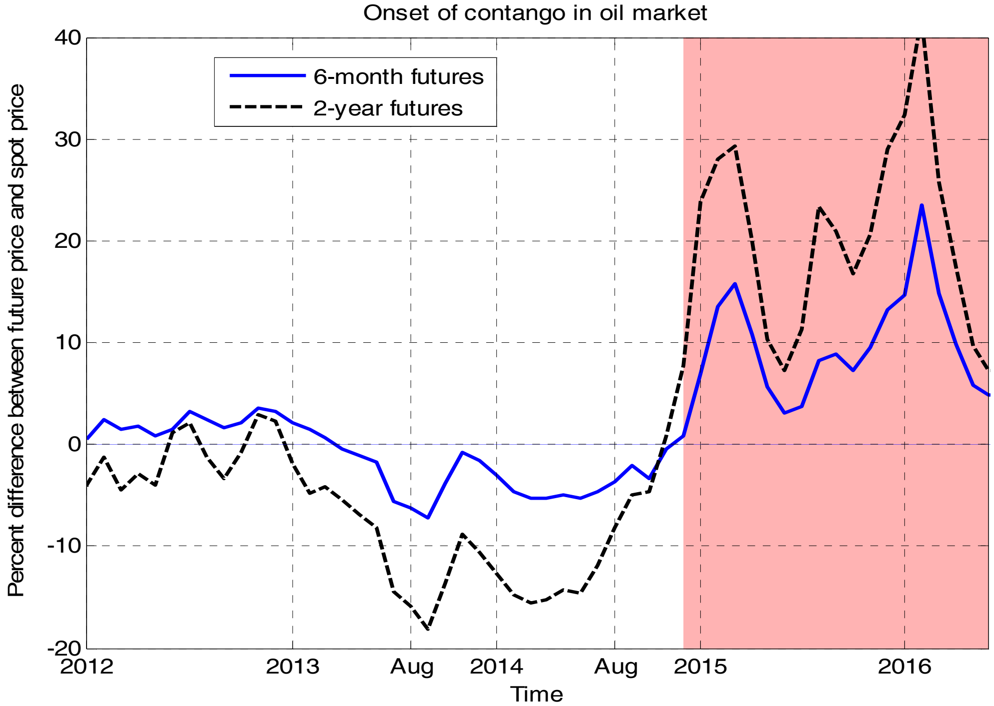

Figure 1: Oil Price Contango Over Time

This figure plots the relative contango of the crude oil futures curve at different points in time. The shaded area is the contango time period we focus on in our study. The solid line represents the difference between the 6 month futures price and the spot price, while the dotted line represents the difference between the 2 year futures and the spot price. Data on crude oil futures prices is from Bloomberg.

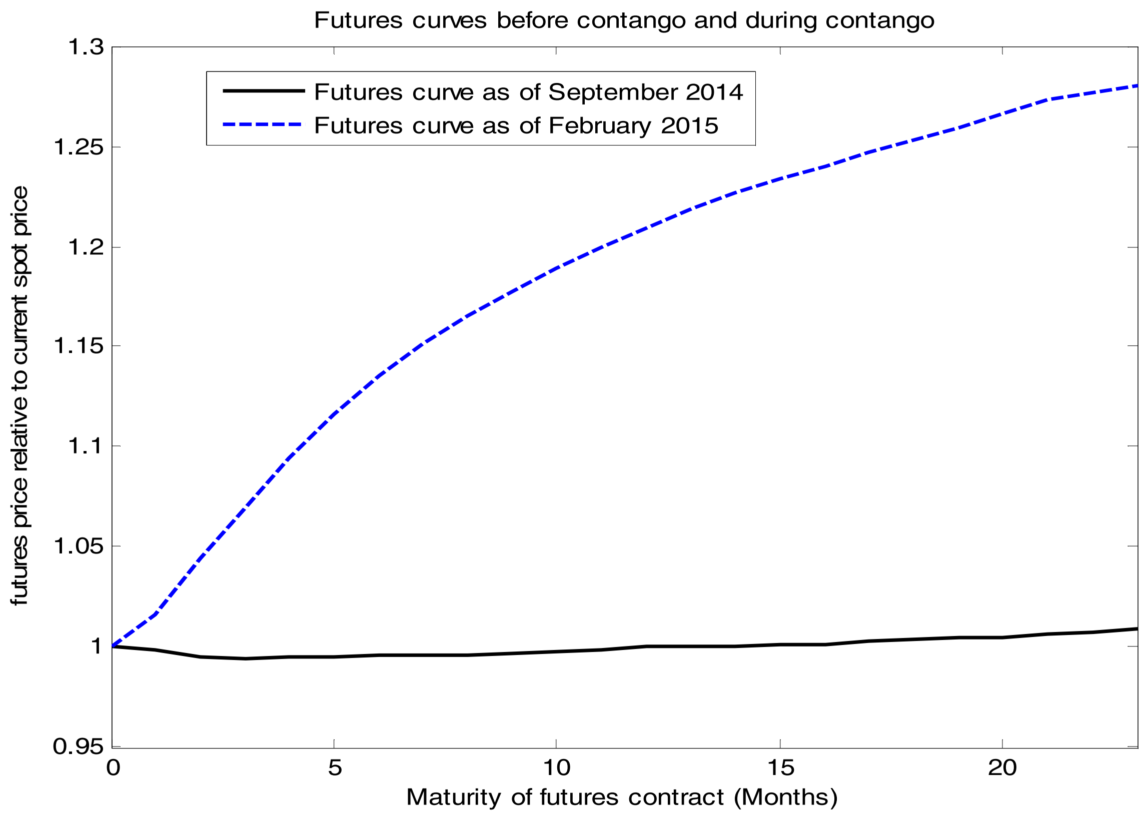

Figure 2: February 2015 oil price futures curve vs. September 2014 oil price futures curve

This figure plots the futures curve of crude oil at two different points in time. One time period is September 2014, prior to the contango. The other is February 2015, during our contango time period. The scale on the Y axis scales prices to the spot price on each of these dates, so that the futures curve in the two time periods is comparable. Data on futures prices is from Bloomberg.

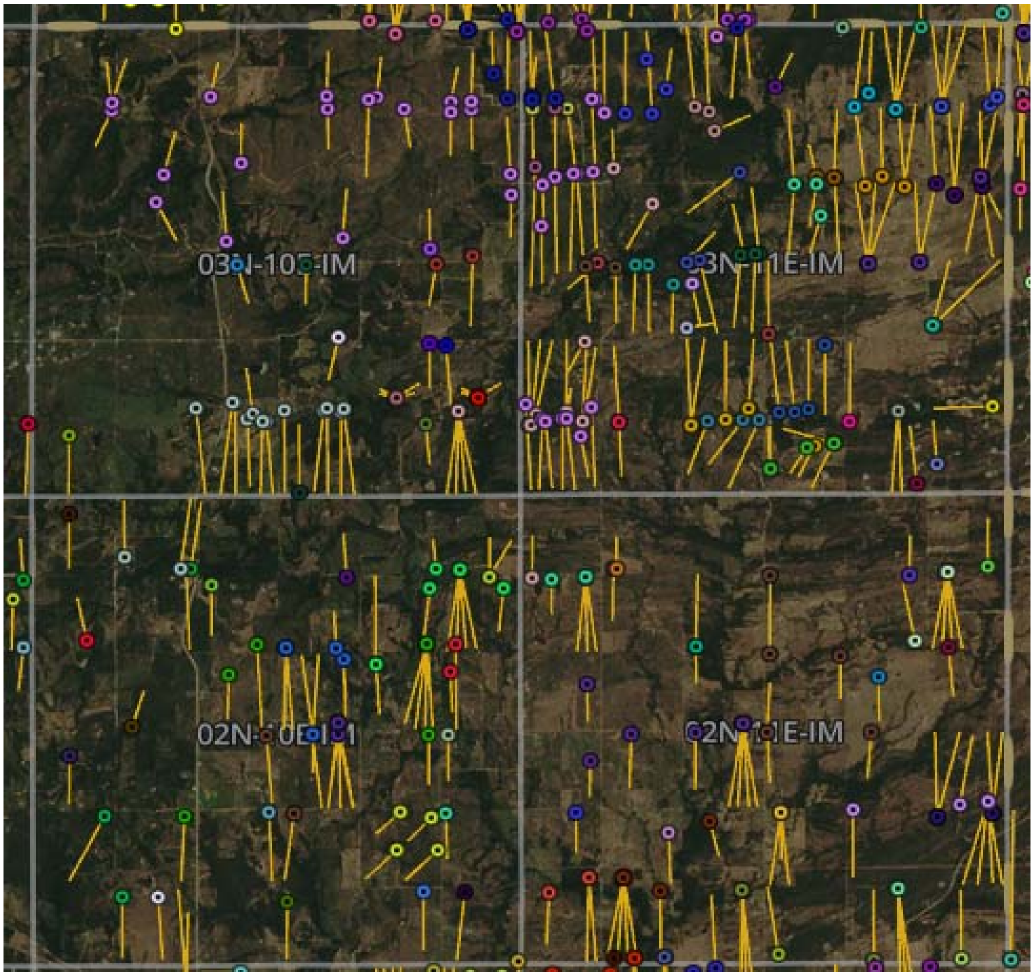

Figure 3: Density of Oil Wells in Woodford Shale, Oklahoma

This figure illustrates the density of oil fracking operations in the Woodford Shale, Oklahoma. Each square represents a 6 mile by 6 mile area (township), which is composed of 36 individual drilling tracts (leases). Each dot reprents the wellhead, and each individual line illustrates the direction of horizontal wellbore for each individual well.

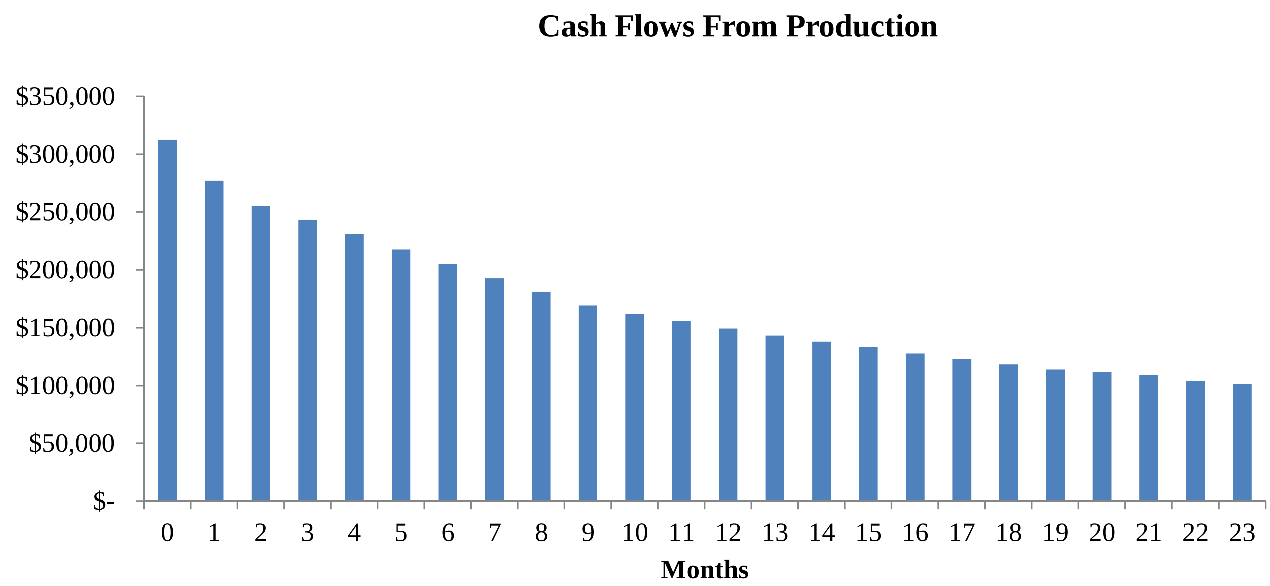

Figure 4: Production Cash Flows From Well

This figure plots the after tax cash flows from an average well's production. Production is based on the average production profile of 2,484 wells in North Dakota in 2014. Average royalty rate is assumed to be 3/16, corporate taxes are assumed to be 38%, oil and gas severance tax is assumed to be 3%. The futures curve used to project these cash flows is the average of the NYMEX futures curve during the contango period in our sample.

Panel A: After tax cash flows of decision to complete a well today or delay produciton for 1 month

Month Since Completion	After Tax Cash Flows ($000)	
	Immediate Well Completion	Well Completion is Delayed by 1 month
0	(3,187)	
1	277	(3,117)
2	255	283
3	243	260
4	231	247
5	218	234
6	205	220
7	193	207
8	181	195
9	169	183
10	162	171
11	156	163
...		
30	82	84
31	80	82
32	76	80
...		

Panel B: Relative percent change in NPV from delaying production.

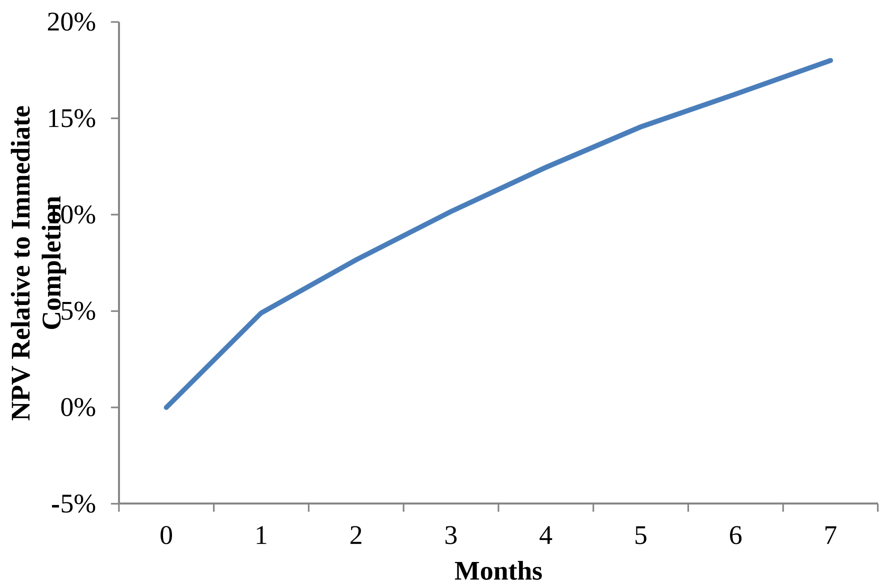

Figure 5: Cash Flow Implicaitons of a Decision to Delay Production
Panel A presents cash flows implicaitons of two decision: immediate well completion and delaying of well completion by 1 month. Panel B estimates the increase in NPV as a result of a decision to delay production by a given number of month as a percentage of NPV of an immediately completed well. Production is based on the average production profile of 2,484 wells in North Dakota in 2014. Average royalty rate is assumed to be 3/16, corporate taxes are assumed to be 38%, oil and gas severance tax is assumed to be 3%. The futures curve used to project these cash flows is the average of the NYMEX futures curve during the contango period in our sample. The calculations in this figure assume a discount rate of 10%.

Table 1. Summary Statistics

This table contains summary statistics for firm-level financial variables (market leverage, profitability, assets, and market-to-book ratios), well completion time, and the number of wells per firm. We have data for 69 oil producers that spud a total of 3,573 wells during the relevant time period. Market leverage is defined as total book debt divided by equity market cap plus debt. Profitability is defined as earnings before interest taxes depreciation and amortization scaled by lagged assets, and is the quarterly profitability as of the quarter prior to the contango period begins (September 2014). Assets is total assets, and Tobin's q is the market value of equity plus debt divided by book assets. Panel B compares the low leverage and high leverage firms that we focus on for comparisons in our sample. Our main comparisons are based on firms in the top quintile of leverage (high leverage) to all other firms (low leverage).

Panel A: Full Sample Summary Statistics

Dependent variable	*N*	Mean	Std. Dev.	p25	p50	p75
Months from Project Start to Completion	3573	4.57	2.60	3.00	4.00	5.00
Control variables						
Market Leverage	69	0.31	0.19	0.17	0.26	0.41
Profitability	69	0.04	0.02	0.03	0.04	0.05
Size (assets in $millions)	69	30,600	70,890	2,171	5,833	17,846
Tobin's q	69	1.17	0.44	0.84	1.08	1.43
Number of Wells Pre Super Contango (2013)	69	20.32	26.96	3.00	10.00	26.00
Number of Wells Super Contango (2014)	69	31.23	35.35	6.00	19.00	40.00

Panel B: Treatment (High Leverage) vs. Control (Low Leverage) comparison

	Low Leverage	High Leverage	Difference
Market Leverage	0.24	0.62	0.38***
Profitability (Q3 2014)	0.04	0.04	0.00
Size (assets in $millions)	28,682	3,978	-24,704
Tobin's q	1.28	0.86	-0.42***

Table 2: Leverage and Production Decisions, Univariate Test

This table reports the average number of months to complete a well after it is spud for wells that are spud during the pre-contango period and the contango period The pre-contango period is composed of wells started in September, October, and November of 2013, the year prior to the super-contango period. The contango period is composed of wells started in September, October, and November of 2014, just before contango began. We present average months in each period by quintiles of operating firms' market leverage. For each quintile, we report the difference between the average time to completion in late 2014 and the average time to completion in 2015.

	Pre-Super Contango	Super Contango	Difference
Leverage Quintile 5 (Highest Leverage)	3.57	3.75	0.18
Leverage Quintile 4	3.53	5.19	1.66***
Leverage Quintile 3	4.02	5.13	1.11***
Leverage Quintile 2	4.18	4.76	0.58***
Leverage Quintile 1 (Lowest Leverage)	4.04	5.07	1.03***

Table 3: Measuring Differences in Investment Opportunities

This table reports summary stats and regressions which estimate whether firms with high leverage, defined as leverage above the 80th percentile, have different investment opportunities than low leverage firms. This table provides project level comparisons of well costs and production across both high leverage and low leverage firms. Panel A reports univariate comparisons and Panel B reports comparisons controlling for geography and time fixed effects. The sample is composed of wells for which initial production and costs are available from regulatory disclosures to the Oklahoma Corporation Commission in 2013 and 2014. This sample overlaps, but is different from our main sample, in that our main sample is composed of all wells started in September, October, and November of 2014 across all states. The Oklahoma data is the broadest available data set to measure both well costs and initial production to assess whether within a given geography. The unit of observation in the regression in Panel B is cost and initial production for well j in year t. The regression specification includes both time and geography fixed effects based on townships which are geographic areas in which two wells are no further than 8.48 miles apart. Standard errors are clustered by firm and are reported in brackets below the coefficient estimates. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

Panel A

	High Leverage	Low Leverage	Difference
Well Cost	$3,885,710	$7,306,493	-$3,420,783***
N	228	706	
Well Initial Production (Barrels of Oil Per Day)	241	364	-123***
N	738	1276	

Panel B

	Dependent Variable = Cost		Dependent Variable = Initial Production	
	Cost	Ln(Cost)	Initial Production	Ln(Initial Production)
	(1)	(2)	(3)	(4)
High Leverage Dummy	-130,709	-0.055	24.989	0.021
	[273,682]	[0.036]	[28.912]	[0.110]
Geog FE_j	Yes	Yes	Yes	Yes
$TimeFE_t$	Yes	Yes	Yes	Yes
N	934	934	1322	1319
R^2	0.395	0.419	0.395	0.419

Table 4: Leverage and Production Decisions

This table estimates how the time to project completion varies across firms based on leverage. The unit of observation is at the well *j*, firm *i*, year *t* level. The dependent variable is the number of months between when a project is started and when production for the project begins. The regression is a form of difference in differences. The first difference compares wells spud in the pre-contango period ($Contango_t = 0$) to the post-contango period ($Contango_t = 1$). The pre-contango period is composed of wells started in September, October, and November of 2013, the year prior to the super-contango period. The contango period is composed of wells started in September, October, and November of 2014, just before the oil market entered contango in December of 2014. The second difference compares firms with different levels (quintiles) of leverage. Leverage is based on a firm's market leverage as of September 30, 2014 and is absorbed by firm fixed effects. Market leverage is defined as total debt divided by debt plus equity market cap. Firms with asset based lending are firms that have lines of credit linked directly to collateral asset values and are redetermined periodically. The regression specifications include firm and geography fixed effects based on townships which are geographic areas in which two wells are no further than 8.48 miles apart. Standard errors are clustered by firm and are reported in brackets below the coefficient estimates. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Dependent Variable = Months to Production			Dependent Variable = Ln(Months to Production)		
	(1)	(2)	(3)	(4)	(5)	(6)
$Contango_t$	1.077***	1.077***	1.093***	0.150***	0.193***	0.195***
	(0.310)	(0.202)	(0.203)	(0.047)	(0.038)	(0.038)
$Contango_t$ × Leverage p20 p40 D_i	-0.269			0.003		
	(0.611)			(0.121)		
$Contango_t$ × Leverage p40 p60 D_i	0.174			0.104		
	(0.530)			(0.082)		
$Contango_t$ × Leverage p60 p80 D_i	0.196			0.081		
	(0.405)			(0.077)		
$Contango_t$ × Leverage p80 and up D_i	-1.001**	-1.002***		-0.123*	-0.165**	
	(0.419)	(0.369)		(0.070)	(0.066)	
$Contango_t$ × Asset Based Lending Leverage p80 and up D_i			-1.198***			-0.190***
			(0.308)			(0.059)
$FirmFE_i$	Yes	Yes	Yes	Yes	Yes	Yes
6 Sq Mile Geog FE	Yes	Yes	Yes	Yes	Yes	Yes
N	3300	3300	3300	3300	3300	3300
R^2	0.50	0.50	0.50	0.52	0.52	0.52

Table 5: Robustness Tests

This table estimates whether other observables (Log Assets, Profitability, and Market to Book) may have a differential effect on firms in the contango time period. All firm-level variables are absorbed my firm fixed effects. Standard errors are clustered by firm and are reported in brackets below the coefficient estimates. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Dependent Variable = Months to Production			
	(1)	(2)	(3)	(4)
Contango_t	0.542	2.130*	0.790	1.793
	(0.519)	(1.206)	(0.720)	(1.193)
$\text{Contango}_t \times$ Leverage p80 and up D_i	-0.916**	-1.196***	-0.896*	-1.124**
	(0.386)	(0.378)	(0.478)	(0.456)
$\text{Contango}_t \times \text{Profitability}_i$	11.988			6.779
	(9.667)			(12.472)
$\text{Contango}_t \times$ Log Assets_i		-0.105		-0.103
		(0.123)		(0.111)
$\text{Contango}_t \times$ Tobin's q_i			0.198	-0.025
			(0.483)	(0.573)
FirmFE_i	Yes	Yes	Yes	Yes
6 Sq Mile Geog FE	Yes	Yes	Yes	Yes
N	3233	3233	2930	2930
R^2	0.51	0.51	0.52	0.52

Table 6: Production Decisions and Debt Renegotiations, Univariate Tests

This table reports results of when firms decide to initiate production on a well, relative to when a firm renegotiates its credit agreement or resets its borrowing base with its creditors. The sample for this test is composed of firms with asset based lending and with borrowing base collateral redeterminations scheduled for the Spring of 2015. These renegotiations took place in the Spring of 2015 and were staggered over February, March, April, and May 2015. The unit of observation is well j for firm i in month t. The variable of intrest equals 0 if a well was not turned on to start producing, and equals 1 if production was initiated in that month. Therefore the figures reported can be interpreted as the proportion of wells that were started in the Fall of 2014, which were completed and which initiated production in different months relative to a credit renegotiation. High leverage firms are firms above the 80th percentile of leverage as of September 30th 2014, the last quarter prior to the beginning of the super-contango period. Standard errors are clustered by firm and are reported in brackets below the coefficient estimates. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Probability of Well Starting Production							Difference
	Time 0 = month of debt renegotiation							Well Starts$_{t=-1}$ - Well Starts$_{t=0}$
	-3	-2	-1	0	1	2	3+	
High Leverage	0.22	0.18	0.21	0.08	0.08	0.04	0.05	0.12***
N	129	238	238	238	238	238	238	
Low Leverage	0.15	0.18	0.12	0.07	0.03	0.03	0.11	0.05***
N	626	640	640	640	640	640	640	
							Difference$_{High}$ - Difference$_{Low}$	0.08**
							p-value	0.02

Table 7: Production Decisions and Debt Renegotiations

This table reports regression estimates of when firms decide to initiate production on a well relative to when a firm renegotiates its credit agreement or resets its borrowing base with its creditors. The sample for this test is composed of all firms, with dummies relative to renegotiations assigned for firms with asset based lending. These renegotiations took place in the Spring of 2015 and were staggered over February, March, April, and May 2015. The unit of observation is well j for firm i in month t. The variable of interest equals 0 if well was not turned on to start producing, and equals 1 if production was initiated in that month. High leverage firms are firms above the 80th percentile of leverage as of September 30th 2014, the last quarter prior to the beginning of the super-contango period. In all regressions, firms that do not have asset based loans, and are therefore not subject to credit renegotiations serve as the baseline control group. The direct effect of the high leverage dummy is absorbed by the firm fixed effects. Standard errors are clustered by firm and are reported in brackets below the coefficient estimates. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Dependent Variable = Well Start (1 if well starts producing in month, 0 otherwise)		
	High Leverage	Low Leverage	All
	(1)	(2)	(3)
Month=-2 to Renegotiation D_t	-0.062	0.017	0.021
	[0.061]	[0.039]	[0.038]
Month=-1 to Renegotiation D_t	-0.022	-0.007	-0.002
	[0.049]	[0.031]	[0.030]
Month=0 to Renegotiation D_t	-0.135**	-0.006	-0.003
	[0.050]	[0.037]	[0.036]
Month=1 to Renegotiation D_t	-0.107**	-0.034	-0.032
	[0.046]	[0.030]	[0.029]
Month=2 to Renegotiation D_t	-0.111***	-0.015	-0.013
	[0.037]	[0.031]	[0.031]
Month≥3+ to Renegotiation D_t	-0.092*	0.074	0.075
	[0.046]	[0.052]	[0.052]
High $Leverage_i$ × Month=-2 to Renegotiation D_t			-0.078
			[0.068]
High $Leverage_i$ × Month=-1 to Renegotiation D_t			-0.012
			[0.054]
High $Leverage_i$ × Month=0 to Renegotiation D_t			-0.122**
			[0.057]
High $Leverage_i$ × Month=1 to Renegotiation D_t			-0.059
			[0.048]
High $Leverage_i$ × Month=2 to Renegotiation D_t			-0.089**
			[0.042]
High $Leverage_i$ × Month≥3+ to Renegotiation D_t			-0.162**
			[0.065]
$FirmFE_i$	Yes	Yes	Yes
$MonthFE_t$	Yes	Yes	Yes
6 Sq Mile Geog FE_j	Yes	Yes	Yes
N	15,051	18,755	20,216
R^2	0.056	0.049	0.052

Table 8: Liquidity and Production Decisions

This table reports summary statistics on the liquidity status of our high leverage sample firms in Panel A. In Panel B the table reports regression estimates of when firms decide to initiate production on a well, relative to when a firm renegotiates its credit agreement or resets its borrowing base with its creditors for high leverage firms with high interest coverage and high leverage firms with low interest coverage. The sample for this test is composed of all firms, with dummies relative to renegotiations assigned for firms with asset based lending. These renegotiations took place in the Spring of 2015 and were staggered over February, March, April, and May 2015. The unit of observation is well j for firm i in month t. The variable of intresest equals 0 if well was not turned on to start producing, equals 1 if it was. High leverage firms are firms above the 80th percentile of leverage as of September 30th 2014, the last quarter prior to the beginning of the super-contango period. The direct effect of the high leverage dummy is absorbed by the firm fixed effects. Standard errors are clustered by firm and are reported in brackets below the coefficient estimates. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

Panel A: Liquidity Statistics for High Leverage Firms

Current Ratio	2.46
EBITDA/Interest	3.18
% of Credit Line Drawn	37.30%
2015 Planned Capex/Operating Cash Flow	1.06

Panel B: High Leverage, High Interest Coverage vs. Low Interest Coverage

	Dependent Variable = Well Start (1 if well starts producing in month, 0 otherwise)		
	Low Interest Coverage	High Interest Coverage	All
	(1)	(2)	(3)
Month=-2 to Renegotiation D_t	-0.073	-0.089**	-0.083*
	[0.074]	[0.043]	[0.043]
Month=-1 to Renegotiation D_t	-0.079	0.069	0.074
	[0.057]	[0.051]	[0.052]
Month=0 to Renegotiation D_t	-0.169**	-0.101*	-0.095*
	[0.066]	[0.055]	[0.054]
Month=1 to Renegotiation D_t	-0.145***	-0.066	-0.063
	[0.043]	[0.087]	[0.086]
Month=2 to Renegotiation D_t	-0.137***	-0.096*	-0.094*
	[0.045]	[0.048]	[0.047]
Month≥3+ to Renegotiation D_t	-0.124**	-0.061	-0.059
	[0.057]	[0.059]	[0.058]
High $Coverage_i$ × Month=-2 to Renegotiation D_t			0.012
			[0.086]
High $Coverage_i$ × Month=-1 to Renegotiation D_t			-0.155**
			[0.074]
High $Coverage_i$ × Month=0 to Renegotiation D_t			-0.074
			[0.082]
High $Coverage_i$ × Month=1 to Renegotiation D_t			-0.080
			[0.093]
High $Coverage_i$ × Month=2 to Renegotiation D_t			-0.042
			[0.061]
High $Coverage_i$ × Month≥3+ to Renegotiation D_t			-0.066
			[0.077]
$FirmFE_i$	Yes	Yes	Yes
$MonthFE_t$	Yes	Yes	Yes
6 Sq Mile Geog FE_k	Yes	Yes	Yes
N	14575	13985	15051
R^2	0.055	0.055	0.057

Table 9: Well Initial Production Before vs. After Debt Renegotiation

This table reports the initial production from wells of high leverage sample firms right before a credit renegotiation vs. right after a credit renegotiation. Data on initial production from wells was collected from a subsample of firms which have operations in Texas (completion reports collected from the Texas Railroad Commission) and in Oklahoma (completion reports collected from the Oklahoma Corporation Commission).

	Initial Production (Barrels of Oil per Day)		
	Before Renegotiation	After Renegotiation	Difference
High Leverage Firms	417.34	291.71	125.64*
N	151	41	
	Initial Production (Log(Barrels of Oil per Day))		
	Before Renegotiation	After Renegotiation	Difference
Low Leverage Firms	5.57	5.23	0.34*
N	151	41	

Table 10: High Collateral Impact vs. Low Collateral Impact

This table reports a similar specification to Table 6, but subdivides by well type. Wells that have high collateral impact are wells on leases with no wells, in which firms will get collateral credit for initiating production as well as for some prospective adjacent well locations. Low collateral impoact are wells on leases with other wells, where there will be fewer prospective adjacent well locations.

	Probability of Well Starting Production							Difference
	Time 0 = month of debt renegotiation							Well $\text{Starts}_{t=-1}$ - Well $\text{Starts}_{t=0}$
	-3	-2	-1	0	1	2	3+	
Single Well Lease (High Collateral Impact)								
High Leverage	0.26	0.19	0.24	0.08	0.08	0.05	0.03	0.16
Low Leverage	0.14	0.16	0.12	0.09	0.04	0.05	0.13	0.03
							$\text{Difference}_{\text{High}}$ - $\text{Difference}_{\text{Low}}$	0.13***
							p-value	0.01

	Probability of Well Starting Production							Difference
	Time 0 = month of debt renegotiation							Well $\text{Starts}_{t=-1}$ - Well $\text{Starts}_{t=0}$
	-3	-2	-1	0	1	2	3+	
Multi Well Lease (Low Collateral Impact)								
High Leverage	0.17	0.18	0.14	0.10	0.07	0.02	0.07	0.05
Low Leverage	0.17	0.19	0.12	0.06	0.03	0.01	0.09	0.06
							$\text{Difference}_{\text{High}}$ - $\text{Difference}_{\text{Low}}$	-0.01
							p-value	0.87