Drilling and Debt

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Abstract

This paper documents a new debt related investment distortion. Using detailed project level data in the Oil and Gas industry, we find that highly levered firms pull forward investment, completing projects early 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 is one of the central questions in finance. Incentive conflicts between debt and equity claimants have the potential to result in inefficient and value destroying decisions (Jensen and Meckling, 1976). 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 debt related investment distortion, and link this distortion with firms' incentives to create collateral. Specifically, we find that high-leverage firms pull forward investment, completing projects early, particularly prior to credit renegotiations. Our new detailed data on project level cash flows allows us to show that these actions are at the expense of higher net present value (NPV) decisions at the project level. We further show that these negative investment distortions at the project level are likely to enhance collateral values and potentially aim to increase firms' access to finance. These findings highlight a previously unexplored hidden cost of collateral based financing.[2]

Identifying how debt affects the actions of firms is empirically challenging. First, it is difficult to observe actions at the project level and identify how these actions 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 and its value to be observable. Third, 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.

[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).

[2] We are careful to note, that the benefits of enhanced collateral and increased access to credit may offset the loss in project value at the firm level.

We exploit an empirical setting which allows us to make significant progress on each of these challenges. Specifically, we use detailed project-level completion decisions on North 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 high frequency *project level* company decisions and can quantify the cash flow effect of completing an individual oil well versus delaying completion of said oil well. Our dataset contains detailed project-level data on 3,557 North American shale oil well 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.

Second, the 2014-2015 contango episode offers a clear episode in which completion should be delayed. During this period, oil spot prices were significantly lower than oil futures prices. In February 2015, for example, six-month oil futures prices were 11% higher than spot prices. The futures curve provides us with a clear counterfactual as it allows us to estimate the value of delaying completion. We show that a decision to accelerate well completion and to start oil production early is not value maximizing at the project level.[3] We estimate that delaying production by a mere one month would have enhanced an individual well NPV by 5.0%.

Third, the detailed project level data allows us to make progress in controlling for the endogeneity of potential differences in *investment opportunities* across high-leverage and low-leverage firms (Lang, Ofek, and Stulz, 1996; Ahn, Denis, and Denis, 2006). Using precise well location data, we control for differences in investment opportunities (well/project quality) via a set of granular township (6 by 6 mile) geography fixed effects.

[3] Production from shale oil projects is highest during the first month and declines significantly in each subsequent month. Consequently, pricing at the time of initial production is a key determinant of project level returns.

Finally, we exploit the fact that Oil and Gas industry credit agreements are characterized by rigid seasonal credit renegotiation schedules defined in advance. In this industry renegotiations are typically not a consequence of covenant violations, distress, or defaults, but rather a standard part of the debt contract lifecycle. The timing of the credit renegotiations we study in our sample can be considered plausibly exogenous with respect to the oil price contango period. These credit agreement renegotiations and the contango period serve as the foundation of two separate difference-in-differences (DiD) analyses. While we do not offer an instrument for leverage, the combination of two different DiD empirical designs and granular geographic fixed effects imposes significant hurdles on non-debt related interpretations of our results.

Our first DiD analysis compares well completion decisions during the pre-contango period versus the contango period for high-leverage relative to low-leverage firms. We find that high-leverage firms (those in the top 20% of the leverage distribution) start producing, on average, 1.0 months earlier during contango, resulting in about 5.0% loss in the project net present value (NPV) or $124,000 per project. For an average firm, the aggregate effect of this investment distortion across the projects we focus on in this study amounts to about 1.2% loss in equity value. We further show that firms' heterogeneity in profitability, size, or market-to-book is not associated with variation in timing of well completions. This evidence suggests that non-debt related explanations are unlikely to drive our results.

In the second diff-in-diff setting, we show that the acceleration of well completion 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.

The question remains, however, as to the economic channel 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 limits the number of economic explanations capable of accounting for our results.[4] In the second half of the paper we evaluate two debt-related channels that could be driving the distortion in timing of investment and project completions we observe: (i) liquidity and cash-flow needs; and (ii) collateral constraints associated with credit agreements.

We find it unlikely that the decision to accelerate well completion and production is driven by liquidity or cash flow needs. A firm in our sample has to incur, on average, $3.5 million in capital expenditures to complete a well producing at most $0.35 million in EBITDA monthly. 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 20 months, at the earliest. These project-level cash flow patterns also, almost mechanically, rule out financial covenant-based explanations.[5] We collect detailed data on liquidity ratios and borrowing availability, and find that despite firms having high-leverage, neither current ratios, interest coverage ratios, nor credit facility availability indicate impending liquidity challenges at the time of credit renegotiations.

We then evaluate whether our findings could be driven by firms' efforts to increase the value of the collateral used to back their credit agreements. We find evidence consistent with the collateral based explanation by exploiting cross-sectional heterogeneity in how well productivity and geographic location affect collateral values assigned by banks. First, lenders ascribe higher collateral value to completed wells, and more so if they are characterized by higher production volume.[6] We find that prior to debt renegotiations, high-leverage firms complete wells that have

[4] We provide an extensive discussion of potential non-debt related interpretations of our results in Section 3.3.
[5] Financial covenant metrics are typically backward looking (e.g., current debt to trailing 12 month EBITDA). Consequently, expending capital (funded by debt on the margin) to complete a well would adversely affect a firm's near term financial covenant ratios, as debt immediately goes up, but the cash flow (EBITDA) from project completion is not recognized in its entirety for the calculation of covenant metrics for 12 months.
[6] In Section 3.4 we offer detailed discussion of OCC guidance on estimating collateral values for Oil and Gas lending that provides additional insight on the collateral value estimation procedures adopted by lenders.

43% higher daily production relative to those completed by the same firms after debt renegotiations.

Second, we exploit the fact that newly completed wells also offer a high quality signal about the value of neighboring *undeveloped* oil reserves. The geographic proximity of undeveloped reserves to producing well(s) reduces asymmetric information and allows lenders to assign higher collateral values to even nonproducing wells.[7] As such, 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 existing producing wells. We find that prior to credit agreement negotiations, high-leverage firms are more likely to complete wells on leases with no producing wells. We estimate that such acceleration of well completion increases collateral value by 6.9% to 13.8%, relative to delaying production in line with low-leverage firms. These results are consistent with firms creating collateral to mitigate adverse selection problems linked to information asymmetry and moral hazard in lending.

Overall, our findings highlight a novel debt related investment distortion. 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 (Aghion and Bolton, 1992; Dewatripont and Tirole, 1994). The empirical literature documents that covenant violations result in significant changes in firms' investments (Chava and Roberts, 2008; Roberts and Sufi, 2009). Both streams of literature argue that covenants lead to Pareto improving reallocation of control rights and better investment outcomes.

We add to this literature by documenting that collateral constraints and debt renegotiations can create negative investment distortions even before the potential reallocation of control rights to debt-holders. Our evidence indicates that highly levered firms sacrifice 1.2% of equity value even before the renegotiations and in the absence of covenant violations.[8] 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*. In contrast, we show that contract restrictions and renegotiations can be costly as they can lead to *value decreasing* actions by equity holders.

We also add to the expansive literature exploring the role that collateral plays in alleviating the financial frictions stemming from moral hazard and adverse selection effects and thus enhancing firms' access to capital.[9] Not surprisingly, collateral plays a particularly crucial role for higher-default-risk firms (see, e.g., Berger and Udell, 1990). Our results are consistent with this literature. We document that highly levered firms are disproportionately more likely to distort investment timing in ways that adversely affect the value of their projects but enhance collateral values. Furthermore, Benmelech and Bergman (2009) show that collateral allows firms to reduce the costs of external debt financing and expand debt capacity. Our evidence highlights previously unexplored hidden costs of collateral based financing, linked to the real investment activity of firms.

Finally, our findings have implications for the studies 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 the 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

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[8] 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.

[9] Benmelech and Bergman (2009) offer extensive discussion of this literature.

of well lifecycles (3-4 years) 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 offer an economic mechanism underlying this finding: the contractual nature of debt financing for oil reserve development creates significant frictions preventing downward adjustment in oil production when oil prices fall unexpectedly.

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 oil price futures curve provides firms (and econometricians) with the expected benefit associated with completing a well at any given date. The detailed high frequency data on the precise timing of well completion allow us to evaluate both the investment outlays and expected project benefits at the firm-project-level. Granular information on well locations and the ability to observe timing of all oil extraction stages allows us to control for a variety of alternative factors linked to investment opportunities. The ability to match the project-level data with firm characteristics allows us to link firms' leverage and their investment response to changes in expected project value.

In this section we provide more details 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 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 price 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. The decline started in late 2014 and was rapid with spot prices falling below $50 per barrel in January of

2015. At that point 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) and 6-month futures prices exceeded the spot price by over 10%. It was a drastic change from the backwardation in oil markets just two months prior. The 2015 futures curve exhibited dramatic deviations from spot prices across all maturities. Figure 2 compares the futures curve as of February 2015 to one as of September 2014.

The 2014-2015 contango episode was unprecedented as futures prices exceeded the spot price by more than *three standard deviations* relative to historical data. It was not only severe in terms of futures price deviation from the spot prices, but 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 severe contango episode of 2014-2015 played an important role in companies' assessment of future expected cash flows from 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).

Consider the well completion incentives under backwardation and contango. Under normal market backwardation, oil producers have incentives 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) wells online as the value of oil produced six months in the future was expected to be at least 11% higher than the value of oil produced in early 2015. More importantly, the pricing uncertainty associated with the decision to delay production could be fully eliminated. The oil producers can enter into a futures contract (at significantly higher prices due to contango) and store the oil underground while waiting to complete a well (at no or minimal marginal cost).[10,11]

Consistent with these arguments, 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. Specifically, we expect the onset of contango to create a disincentive for firms to start production in favor of opening the available reserves later.

2.2. Shale Oil Drilling Overview

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

[10] One can argue that oil and gas firms often hedge their production 12 to 24 months out and, thus, need to produce early to deliver on the ex-ante hedges. However, these hedges do not affect current production decisions in our setting. If a firm sold forward oil in 2014 for delivery in early 2015, a lower cost alternative to initiating production early on a well would be to close out the position by buying physical barrels for delivery at current low spot prices. In this sense, the decision to deliver based on a prior hedge that is in the money is independent of the decision to complete new wells.

[11] During the 2014-2015 contango period physical storage above ground was constrained. Oil in storage hit record levels and many tank farms were full, making above ground storage options prohibitively costly.

over 200 thousand oil wells across five states with shale oil fracking operations: Texas, Oklahoma, North Dakota, Colorado, and New Mexico. Figure 3 provides a snapshot of horizontal drilling activity within a township (6 miles by 6 miles square). In our analysis, we control for heterogeneity in investment opportunities via township geographic fixed effects.

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 spud/ drilled, second the well must be completed which involves hydraulic frackturing. To spud a well, 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 drill onshore wells at an average cost of $3.5 million dollars.[12] The spudded well can sit idle until the company decides to complete or "frack" it.[13] 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 $3.5 million for an average well.

Production typically starts immediately after the well is completed for a number of reasons. First, the completion specialist must 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

[12] Spudding involves drilling the well into the shale and inserting steel well casing and cement down the hole.
[13] 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.

after a well is completed which reduces the amount of oil that can be recovered from a well. Once a well is completed, production typically declines quickly. High initial pressure leads to high initial production. As pressure is released from a well, the production quickly declines month over month. Every day spent not pumping oil from a completed well is, in essence, a day of lost production and cash flows. 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 figure is based on the average production profile of 2,484 wells completed in North Dakota in 2014.

The declining production schedule plays an important role during the period of super-contango described above. Figure 5 illustrates the NPV of a decision to delay production by one to six months using the production volume of a representative North Dakota well. 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, which is the rate that banks use to evaluate a firm's reserves, as well as the discount rate firms use to report reserves to the SEC.[14]

The two-stage oil extraction process – spudding/drilling and completing/fracking – 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 spudding, 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

[14] This calculation assumes that firms sell oil immediately upon producing it. Producing and storing the oil above ground is more costly than delaying production and storing oil underground. 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%.

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-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 RigData, Inc. RigData relies on public filings and relationships with a wide set of drilling contractors to precisely track the start of every shale well drilling operation in the United States. Our study focuses on shale oil 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/spudding), it does not provide the well completion (fracking) 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 maintain the same calendar months 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. Some wells in our sample are completed as quickly as one month after spud date. Others sit 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.

To address investment-opportunity-based alternative explanations of our results we exploit 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. Finally, we supplement the well project drilling and completion data with additional well characteristics such as well completion costs and production volumes. We obtain this data from regulatory reports where available. For example, North Dakota Industrial Commission provides the production schedules for a subset of wells, but such detailed data is not readily available from regulatory bodies of other states in our sample.

2.4. Firm-level Data.

We hand match individual project-level data on well drilling and completion to a set of public oil and gas companies in Compustat following Gilje and Taillard (2016). 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.

Finally, we hand collect detailed information about public firms' credit lines and debt contracts from SEC filings offered by EDGAR. 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 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 the 2014-2015 contango period and the 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 one 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 2014/2015. 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' real investments.

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 projects or growth opportunities. For example, high-leverage firms may choose to complete wells that require less capital or are more/less productive. Using the subset of wells for which we have costs and initial production data, Panel A of Table 3 confirms that important differences in project type exist across high- and low-leverage firms. To control for this heterogeneity in well quality we exploit a set of granular 6×6 mile (township) 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 $(6^2+6^2)^{1/2}$ of each should not exhibit dramatic differences in these characteristics.

Panel B of Table 3 illustrates the efficacy of 6×6 mile geographic fixed effects. We find that the combination of fine geography and firm-level fixed effects explain the vast majority of heterogeneity in well costs and production volumes. 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 fine geographic fixed effects.

Armed with the ability to effectively and control for investment opportunities, we implement a regression analysis that examines the effect of contango on well completion times of high-versus-low-leverage firms using the following regression equation:

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

where $Time\ To\ Completion_{ijt}$ is the number of months between the start of well j spud date and its first production date. The unit of observation is well j of firm *i* at time *t*. $Contango_t$ is an indicator variable that equals one for wells spud in late 2014, the period just prior to the emergence of contango in the oil market. $Contango_t$ is equal to zero for wells spud in 2013, our control backwardation year. $HighLev_i$ is an indicator variable for whether the firm is in the top quintile of the leverage distribution. $Firm\ FE_i$ and $Geography\ FE_j$ 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. We find that in contango, firms in all but the top quintile of the leverage distribution delay well completion by approximately one month. Column (1) demonstrates the nonlinear dependence of wait times during contango on leverage. Firms in the top leverage quintile 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' investment decisions. 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 5.0% 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 has the potential to destroy as much as 1.2% of equity value for high-leverage firms.

The evidence presented in Tables 2 and 4 suggests the 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. We exploit Spring renegotiations of the credit agreements that 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). In this setting evaluating the time to completion is uninformative as for wells drilled in September through November of 2014 the time to completion increases purely mechanically from before renegotiation to after renegotiation. To address this issue we adapt our dependent variable to capture the start of production decisions in an on/off fashion. Specifically, our dependent variable $Well\ Starts\ Production_{ijt}$ takes the value of 1 if a well j of firm i is turned on from idle to producing in a given month *t*, and it is 0 in all other months (both before the completion month and following the completion month). The unit of observation is well *j*, firm *i*, month *t*. Effectively, if one averages the dependent variable within each firm *i*, within each month *t*, one would estimate the share of firm *i* ex ante spudded wells that started producing in a given month *t*. 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 5 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 0.22 at time (t-1) for high-leverage firms suggests that one month prior to renegotiations high-leverage firms complete 22% of wells they had spudded in the fall of 2014. This number drops to 9% in the month after renegotiations, a change that is both economically and statistically significant. To put this into perspective, high-leverage firms complete 145% more wells in the month prior to renegotiation than the month of or one after the renegotiation (0.22/0.09−1). In contrast, low-leverage firms exhibit a much smaller change in well completion percentages around the debt renegotiations dates. We observe a drop from a 12% rate of completion prior to renegotiation to a 7% rate of completion after renegotiation.

We 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 0 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 $Month\ Dummy_{j,i,1,March} = 0$. Firm-level fixed effects control for heterogeneity in firms' characteristics. Since we only consider oil and gas firms behavior over a six month span, these fixed effects control for a wide range of unobservable firm characteristics. Geographic fixed effects control for heterogeneity in project quality and production potential. Month fixed effects control for changes in economic conditions including changes in oil prices and severity of contango. β_{m} are the key coefficients of interest. If debt renegotiations intensify the distortive effects of leverage on investment decisions we expect firms to complete more well just prior to debt renegotiations (*m=-1* or *m=-2*) than after the renegotiation decisions (*m=0* or *m=1*).

The regression analysis results reported in Table 6 are similar to the univariate analysis reported in Table 6. Column (1) of Table 6 documents that between the month prior to and the month of renegotiations, high-leverage firms exhibit an 11.3% drop in the rate of well completion (the coefficient drops from -0.022 to -0.135). This is similar in magnitude to the 0.13 change in completion rate documented in Table 5. In contrast, the number of new wells being brought on line by the low-leverage firms (column 2 of Table 6) does not vary across debt renegotiation dates in a statistically or economically significant way (the coefficient changes from -0.007 in *m=-1* to -0.006 in *m=0*).

3.3. Robustness and Alternative Interpretations

A typical concern that arises with any study that evaluates the effect of leverage on firm financial decisions is that leverage is not randomly distributed. One can argue that our results are due to an omitted variable affecting both debt and completion decisions (managerial quality) or due to firms choosing debt based on their business strategy (reverse causality), leading to alternative interpretations of our tests. Since we do not offer a viable instrument for firms' leverage, such concerns are particularly acute and, thus, deserve a separate discussion.

There are several pieces of evidence that support a debt based interpretation and undermine the argument that our results are due to omitted variable bias or reverse causality. Our identification relies on the contango episode being unanticipated by firms and the market. The 2014-2015 contango episode was exceedingly rare in that the difference between the futures price and the spot price exceeded its average by over three standard deviations. It is hard to argue that firms could have anticipated such severe contango and chose their leverage accordingly. This effectively rules out reverse causality based explanations.

Existing literature documents that investment opportunities could be linked to leverage (Lang, Ofek, and Stulz, 1996; Ahn, Denis, and Denis, 2006): firms with bad investment opportunities could also have high-leverage. If this is the case, the incentives of high-leverage firms to delay production might be weaker than what is captured by our analysis. This explanation, however, relies on heterogeneous effects of contango on firms' incentives to complete different quality wells. In our setting, we show that the heterogeneity in investment opportunities across high- and low-leverage firms is fully captured by very granular geographic fixed effects. After we control for these township-level fixed effects, high- and low-leverage firms exhibit economically similar drilling costs and production volumes across the wells in our sample. Combined, this evidence is inconsistent with alternative interpretations of our main result based on heterogeneity in investment opportunities.

It is possible, however, that heterogeneity in firm-level characteristics other than debt contribute to our result. Panel B of Table 1 shows that high and low-leverage firms differ in terms of size and Market-to-Book. To rule out explanations based on this observed heterogeneity, we augment the analysis presented in Table 4 and add interaction terms between contango dummy and other firm-level control variables. Table 7 shows that heterogeneity in firms' size, profitability, and Tobin's Q *cannot* account for our results. The evidence suggests that high-leverage firms accelerate well completion by one month even after we control for these firm characteristics and their interaction with the Contango dummy, allowing us to conclude that the differential response to contango is associated with high leverage rather than profitability, size, or market-to-book ratios.

One, however, may be concerned about other unobservable differences, such as manager type/quality. For example, both high levels of debt and acceleration of well completion during contango might be artifacts of a particular management style. These arguments are undermined by the evidence of well completion activity around debt renegotiations. It is difficult to argue that changes in completion behavior around debt renegotiation dates could be attributed to economic channels that exclude debt-related forces. It is also hard to offer an economic explanation based on differential managerial behavior, wholly unrelated to leverage, of the completion activity of high- and low-leverage firms pre and post renegotiation. Specifically, Table 5 shows that high-leverage firms complete more wells than low-leverage firms pre-renegotiation (22% versus 12%), but then is similar post renegotiation (9% versus 7%). Combined, our evidence and the institutional features of our setting, substantially raise the bar for a non-debt-driven omitted variable based explanations for our results.

Finally, one might be concerned that the results we document are due to the contemporaneous rapid drop in oil prices rather than firm leverage or contango itself. For example, a drop in spot oil prices might lead to significant changes in asset values that vary across high- and low-leverage firms (see Gilje and Taillard, 2016, 2017). There are several pieces of evidence to suggest that a direct oil price change does not fundamentally alter the interpretation of our results. First, our main tests are based on comparisons of investment decisions within the *same month* into assets of *similar quality* located in the *same township*, but owned by firms with *different leverage*. Second, the key advantage of contango is that it creates an incentive to wait to complete projects even when the oil prices are low.

3.4. 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 channels underlying the effect of debt and renegotiations on sample firms' investment decisions. In this section, we evaluate two channels linked with different aspects of oil and gas firms' access to debt finance: (i) liquidity and cash-flow needs; and (ii) collateral constraints associated with credit agreements.

Liquidity Constraints

First, we assess whether the decision to complete wells early is driven by liquidity or cash flow needs. Several pieces of empirical evidence are not consistent with this channel. We collect data on the debt and liquidity metrics of the high-leverage firms in our sample. We find that high-leverage firms have solid liquidity measures, with an average current ratio (Current Assets/Current Liabilities) of 2.464 and average interest coverage ratio of 3.18. These figures suggest that during our sample period high-leverage firms generate sufficient cash flows to cover interest payments. We also find that the average firm in our sample has significant investment plans, which are on average 106% of current cash flows. Additionally, we collect detailed data on credit limits, and find that high-leverage firms are characterized by spare debt capacity with them utilizing, on average, only 37.3% of their credit lines' credit facility. All these numbers indicate that while high-leverage firms may not have the strongest balance sheets, they are neither vulnerable to imminent default, nor do they face an impending liquidity crunch at the time of credit renegotiation.

Another observation further undermines a liquidity/cash-flow based explanation of our results. A firm in our sample has to incur, on average, $3.5 million in capital expenditures to complete a well producing at most $0.35 million in EBITDA monthly (Figure 4). 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 20 months, on average. Furthermore, the project-level cash flow patterns also, almost mechanically, rule out covenant-based explanations. Given that financial covenant metrics are typically backward looking (e.g., current debt to 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 ratios.

Collateral Constraints

We also evaluate whether our results are driven by firms' attempts to enhance collateral by bringing on-line production. Higher expected future cash flows from wells, for example, increase well-based collateral values and improve firms' ability to secure more and cheaper credit (Benmelech and Bergman, 2009). Such an effect should be more pronounced for riskier firms that depend more on asset-based borrowing (Berger and Udell, 1990).

In the Oil and Gas industry, the expected value of collateral determines the "borrowing base" that sets the upper limit on banks' lines of credit established to finance oil explorations and production operations. Given the asymmetric information about the quality of oil reserves between firms and banks, lenders apply different haircuts to expected cash-flow values of developed and undeveloped wells, as well as to non-producing reserves located in close vicinity of producing reserves versus those located in geographic isolation. Figure 6 offers Office of the Comptroller of the Currency (OCC) reserve classification for oil and gas exploration and production lending as well as suggested "risk adjustment factors" that the OCC recommends banks to apply to the NPVs of different types of reserves in determining the borrowing base.[15] The OCC guidance suggests that the borrowing base is adjusted up when (i) oil prices increase, (ii) new wells are completed and moved from proved undeveloped to proved producing reserves, (iii) higher production volume wells are completed, or (iv) newly completed wells mitigate asymmetric information about the value of other non-producing reserves. Apart from directly affecting the collateral value of completed wells, production decisions have the capacity to increase collateral values assigned to the nonproducing and undeveloped resources.

This suggests that spudded wells exhibit significant heterogeneity in their ability to affect the borrowing base once completed. If collateral is the channel driving our results, one might expect that firms focus on completing wells that potentially have a higher collateral impact. Two factors affect an individual well impact on borrowing base: its production capacity and its ability to mitigate the asymmetric information between firms and banks regarding the value of nonproducing reserves. If firms focus on completing wells that enhance their collateral base on these margins, it would be supportive of a collateral based explanation of our results.

In our empirical analysis of the collateral channel we, first, compare production capacity of wells completed right before a debt renegotiation versus those completed right after. Univariate analysis presented in Table 8 shows that wells completed by high-leverage firms just prior to a credit renegotiation have higher initial production volume 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.[16]

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[15] Comptroller's Handbook for Oil and Gas Exploration and Production Lending, March 2016, Office of the Comptroller of the Currency, https://www.occ.treas.gov/publications/publications-by-type/comptrollers-handbook/pub-ch-og.pdf

[16] Note, that completion of more productive wells does contribute to increase in cash-flows. However, as discussed earlier, due to the sizable CAPEX necessary to complete the well this is unlikely to enhance firms' liquidity positions, particularly prior to renegotiation dates.

Second, we exploit two types of wells that, upon completion, differentially affect the borrowing base even under the same production capacity. Specifically we compare a firm's decision to complete the first well on an oil lease versus a decision to complete a well on a lease with existing producing wells. When a firm initiates production on either of these wells it gets collateral credit for the newly added production volume. But single well lease completion also reduces asymmetric information and enhances the value assigned to other prospective wells within the same lease. We consider these wells to be high collateral impact. In contrast, if other producing wells are located within close proximity, the newly producing wells (within the same lease), all else equal, are unlikely to affect the collateral values of already producing wells or further resolve the information asymmetry about productivity of non-producing reserves on the same lease. We consider these wells to be low collateral impact.

We split our sample of wells based on these well definitions and compare companies' completion behavior within each well category. Table 9 reports the results. We find that the effect we document in Tables 5 and 6 is very strongly pronounced within the sub-sample of single-well leases but weak in the sub-samples of multi-well low collateral impact leases.

One can argue that single-well lease and multi-well leases could differ on other dimensions in addition to their impact on collateral values. For example, if single well leases are, on average, higher-risk higher-reward type projects, then our evidence is indicative of a risk shifting rather than collateral-based mechanism. Using production data a broad set of wells across public and private companies, we verify that single-well leases both exhibit, on average, lower initial production and lower standard deviation of production realizations. This evidence is not consistent with risk-shifting and confirms arguments presented by Gilje (2016). [17]

[17] Note, that the evidence regarding lower risk and lower return nature of single well leases is not inconsistent with evidence indicating higher production capacity of wells opened by high-leverage firms prior to debt renegotiations. In view of the firm-level fixed effects, both results suggest that high-leverage firms tend to open more productive, single wells prior to renegotiation than single wells they open after renegotiation.

Furthermore, we estimate a regression in Table 10 which controls for geography, firm, and time fixed effects, and obtain results similar to our baseline univariate tests.

Taken together, the evidence suggests that in making completion decisions during contango, high-leverage firms are driven by a desire to enhance collateral values (borrowing base). What do firms get for completing their best wells early to generate collateral value? Based on risk factors offered by the Office of the Comptroller of the Currency (OCC) (see Figure 6), we estimate that by accelerating well completion by one month, firms increase their available collateral by 6.9% to 13.8%.[18]

4. Discussion and Conclusion

In this paper we document a new debt related investment distortion and link this distortion with firms' incentives to create collateral. We show that during the 2014/15 contango episode, high-leverage firms complete wells and start production earlier than low-leverage firms. This acceleration of production adversely affects the NPV of oil projects, which, according to our estimates, is equivalent to about 1.2% loss in equity value at the firm level. This adverse investment decision is particularly pronounced among high-leverage firms prior to (pre-scheduled) debt renegotiations. High-leverage firms complete 145% more wells in the month leading to renegotiations than in the month of and after renegotiations (when their rate of well completion is equal to that of low-leverage firms). We further show evidence that strongly supports collateral-based incentives underlying this behavior. In essence, we find that firms forego project level NPV to boost collateral values prior to renegotiations.

The literature has long argued that riskier firms depend more on secured financing (Berger and Udell, 1990). Collateral plays a much more important role in high-leverage firms'

[18] This figure is based on the incremental value that banks ascribe to collateral once wells are complete, based on the OCC guidance of moving reserves from proved undeveloped to proved developed, for the median well in our sample for which we have production and cost estimates.

cost of debt financing and access to debt financing as compared to low-leverage firms (Benmelech and Bergman, 2009). Consistent with this, high-leverage firms are more likely to pay (in a form of lower project NPV) to ensure continued access to cheaper and more abundant asset-based lending. Low-leverage firms can potentially substitute away from asset-based financing to other forms of financing.

However, these results still raise a crucial question, typically invoked by the debt overhang literature: why can't banks renegotiate the debt agreements and allow firms to delay productions and thus capture the additional value (through rent sharing) under contango? Indeed, it seems that any finance professional should see the value left on the table as a result of accelerating production. It also seems that the decision to delay is transparent and easily observable by all parties involved.

The incomplete contracting literature offers two mechanisms that have a potential to create debt renegotiation frictions and explain our results. First, the new debt related investment distortion we document, could be driven by the asymmetric information between lenders and Oil and Gas firms regarding the value of the oil reserves. Under falling oil prices, the high-leverage firms, being more dependent on asset-based lending, have higher incentives to miss-represent the value of their reserves. In such an environment, a high-quality indication of value of non-producing reserves has the potential to reduce asymmetric information and ensure borrowers' continued access to cheaper source of credit. These benefits should be particularly pronounced for high-leverage firms, who likely face higher costs of switching to a different lender given higher adverse selection frictions. Consequently the benefit of forgone project-level returns is higher for high-leverage firms than for low-leverage firms.

The results we document can also stem from moral hazard problems. That is lenders do not want to extend credit to borrowers with incomplete wells and then have the funds invested in bad projects, siphoned off to pay shareholders/management, invested in high risk projects, or otherwise misappropriated while waiting for wells to be completed (Berger and Udell, 1990;

John, Lynch, and Puri, 2003). Similarly, such concerns would be more pronounced for high-leverage firms given their higher reliance on asset-based lending.

Both these mechanisms create incentives for collateral generation by firms at the expense of lower project-level NPVs. Ultimately, equity holders forgo project level returns to enhance collateral value in exchange for greater credit availability. The magnitude of the cost associated with this newly documented friction is significant. Prior literature showed that collateral allows firms to lower cost of capital and increases access to debt finance (Benmelech and Bergman, 2009). Our results indicate the hidden costs of collateral-based debt financing.

Finally, we would like to note that our findings also shed light on a puzzle documented recent literature exploring the violations of Hotteling (1931) in the oil market. It was well known that oil production is price inelastic in the short run (Hamilton, 2009; Kellogg, 2011). This finding was attributed to the lack of production adjustment to price incentives to unique traditional production technology in the oil industry that imposes significant costs on shutting and reopening *traditional* wells that yield oil for 10 to 20 years (Anderson et al., 2014). The new, fracking-based, oil production technology was hypothesized to change this lack of elasticity given short-term nature of well lifecycles (3.5 years) and production pattern that peaks early on in a well's life. However, studies have found that production has remained inelastic despite the new technology (Lehn and Zhu, 2016). Our results offer an economic mechanism underlying this finding: the contractual nature of debt financing for oil reserve development creates significant frictions preventing downward adjustment in oil production when oil prices fall unexpectedly.

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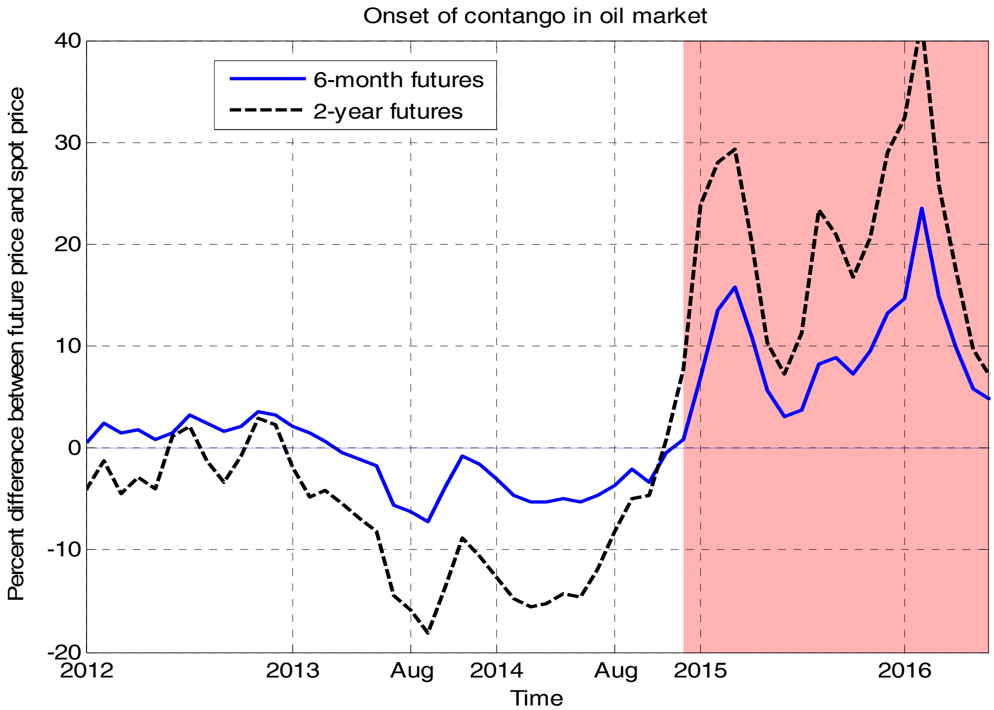

Figure 1: Oil Price Contango Over Time

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.

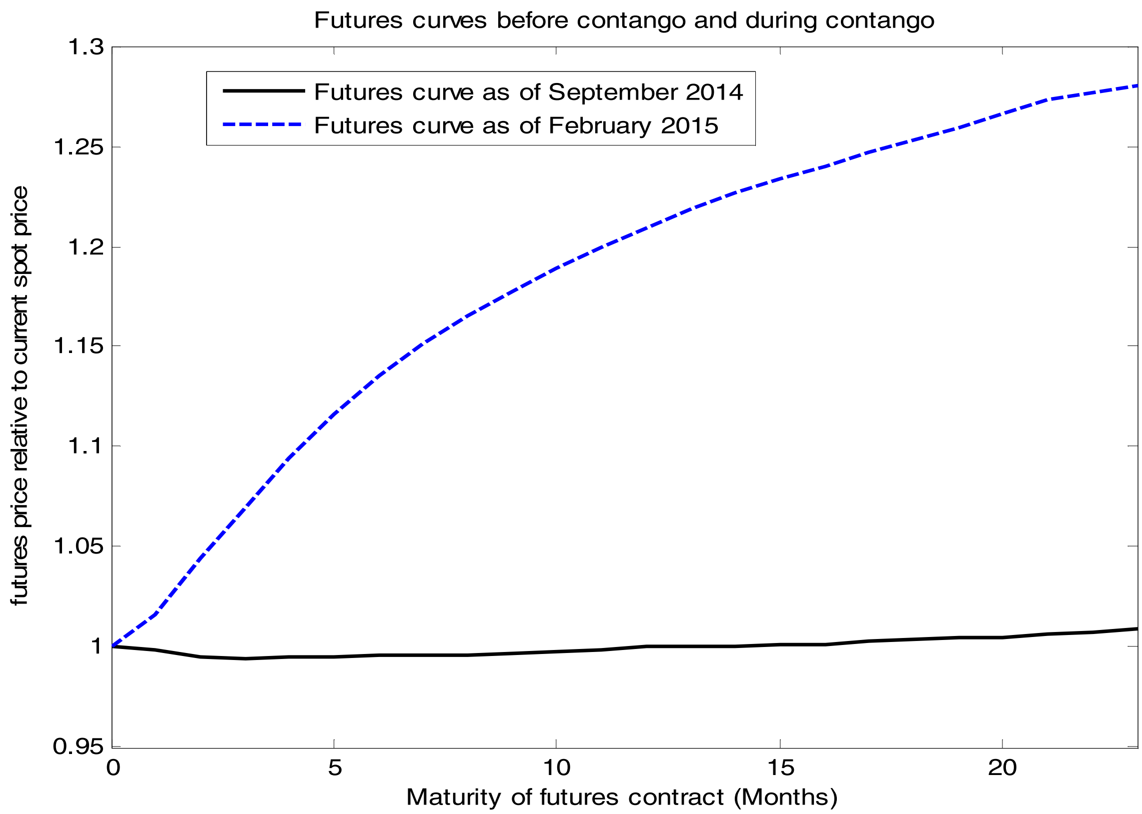

Figure 2: February 2015 oil price futures curve vs. September 2014 oil price futures curve

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.

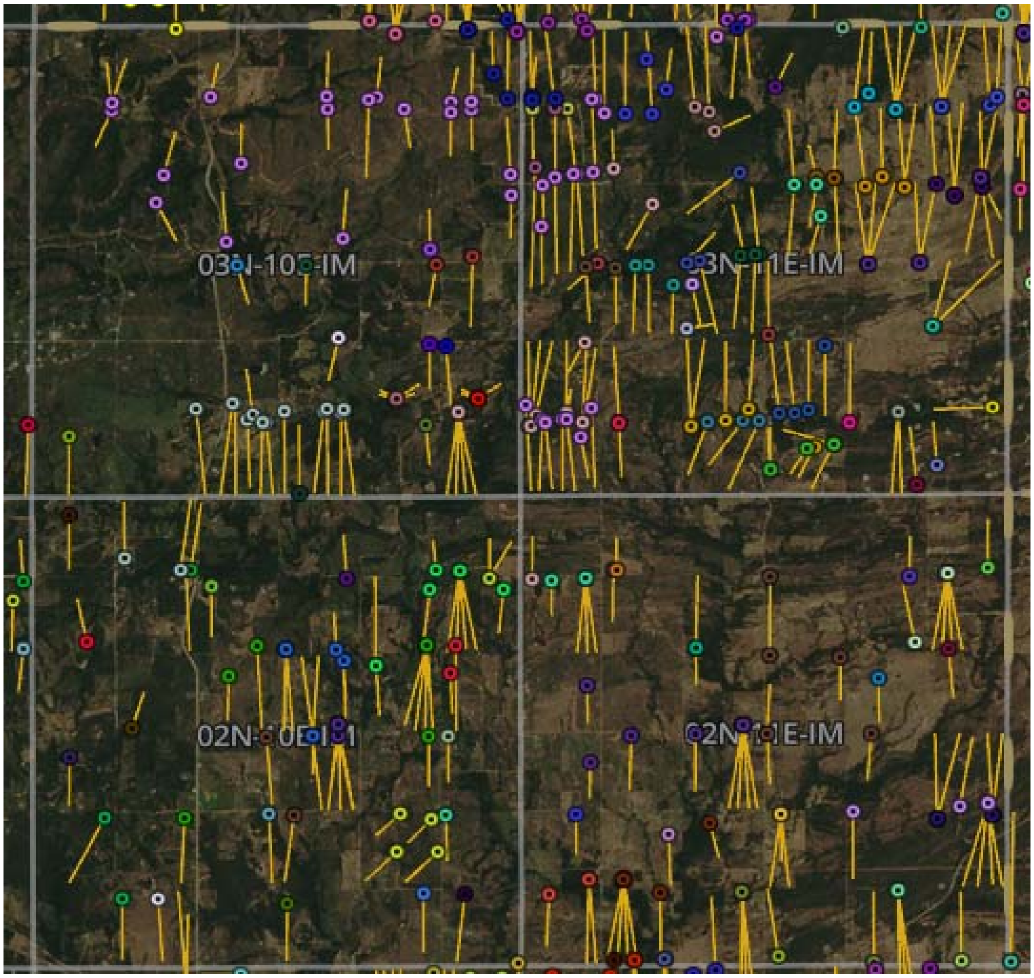

Figure 3: Density of Oil Wells in Woodford Shale, Oklahoma

This figure illustrates oil and gas development 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. Each township is composed of 36 separate one mile by one mile drilling tracts, each of which could have a single well or multiple wells. The wells are color coded by operator.

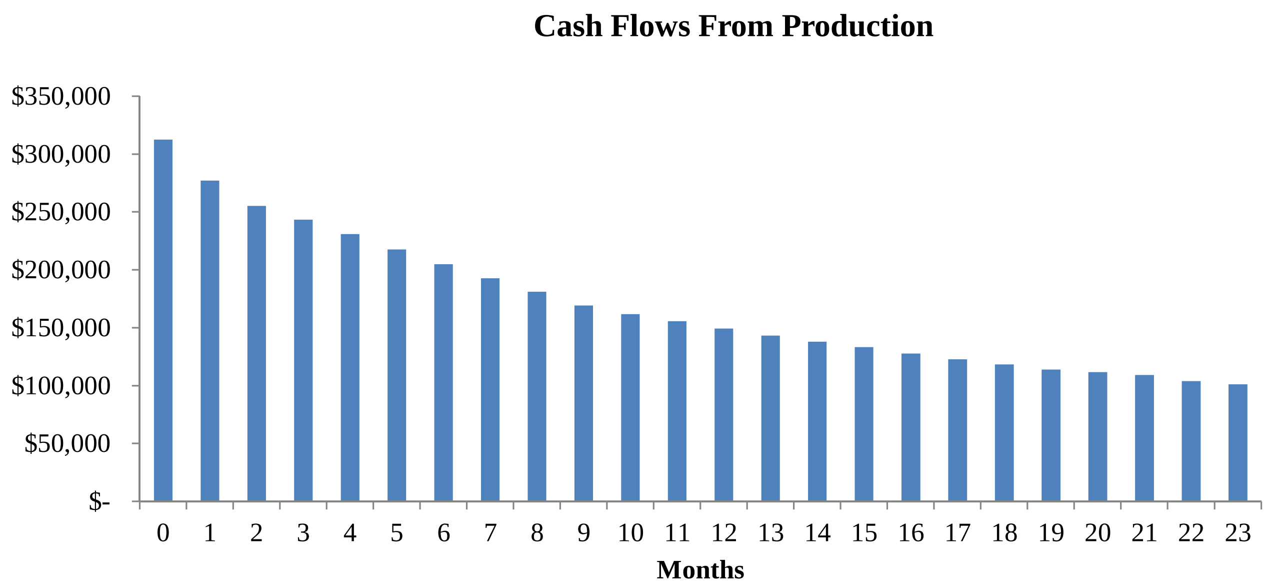

Figure 4: Production Cash Flows From Well
This figure plots the after tax cash flows from an average well's production. Production is based on the average production profile of 2,484 wells in North Dakota in 2014. Average royalty rate is assumed to be 3/16, corporate taxes are assumed to be 38%, oil 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.

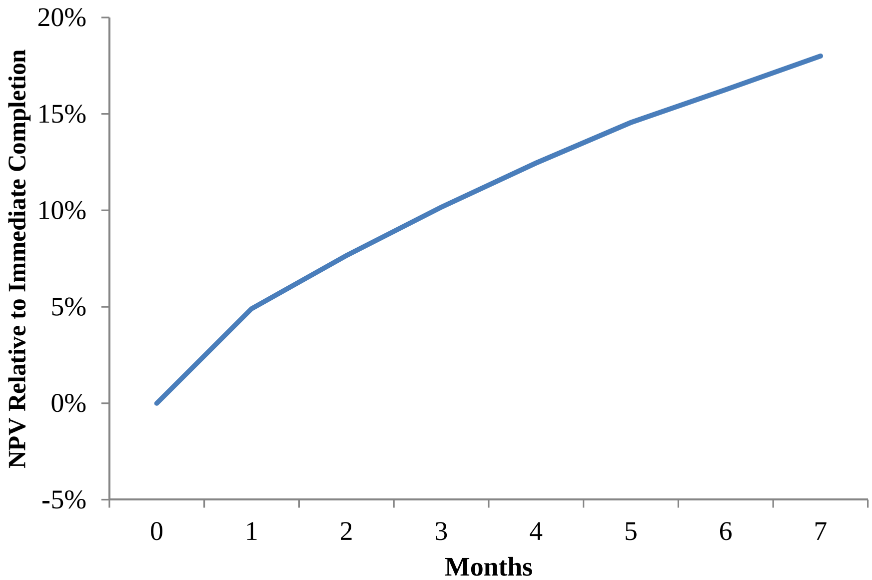

Figure 5: Cash Flow Implicaitons of a Decision to Delay Production
Panel A presents cash flows implicaitons of two decision: immediate well completion and delaying of well completion by 1 month. Panel B estimates the increase in NPV as a result of a decision to delay production by a given number of month 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%.

Figure 6

OCC Oil and Gas Reserves Classification

This figure presents OCC reserves classification and suggested risk adjustment factors (in round brackets) applied in determination of a borrowing base for oil and gas exploration and production lending. OCC recommends that the risk adjustment factors are to be applied to the NPV of the reserve value estimates. Alternatively, lenders can make volumetric adjustments by applying the risk adjustment factors to oil production volumes rather than NPV. Additionally, OCC recommends accounting for the uncertainty of the production volumes for non-producing and undeveloped reserves. * indicates classes that apply only to traditional production technology and is not applicable to fracking wells. The engineering complexity of completion as well as deteriorating pressure in fracking wells effectively eliminates ability to "shut-in" production to wait for higher prices. Source: Comptroller's Handbook for Oil and Gas Exploration and Production Lending, March 2016, Office of the Comptroller of the Currency.

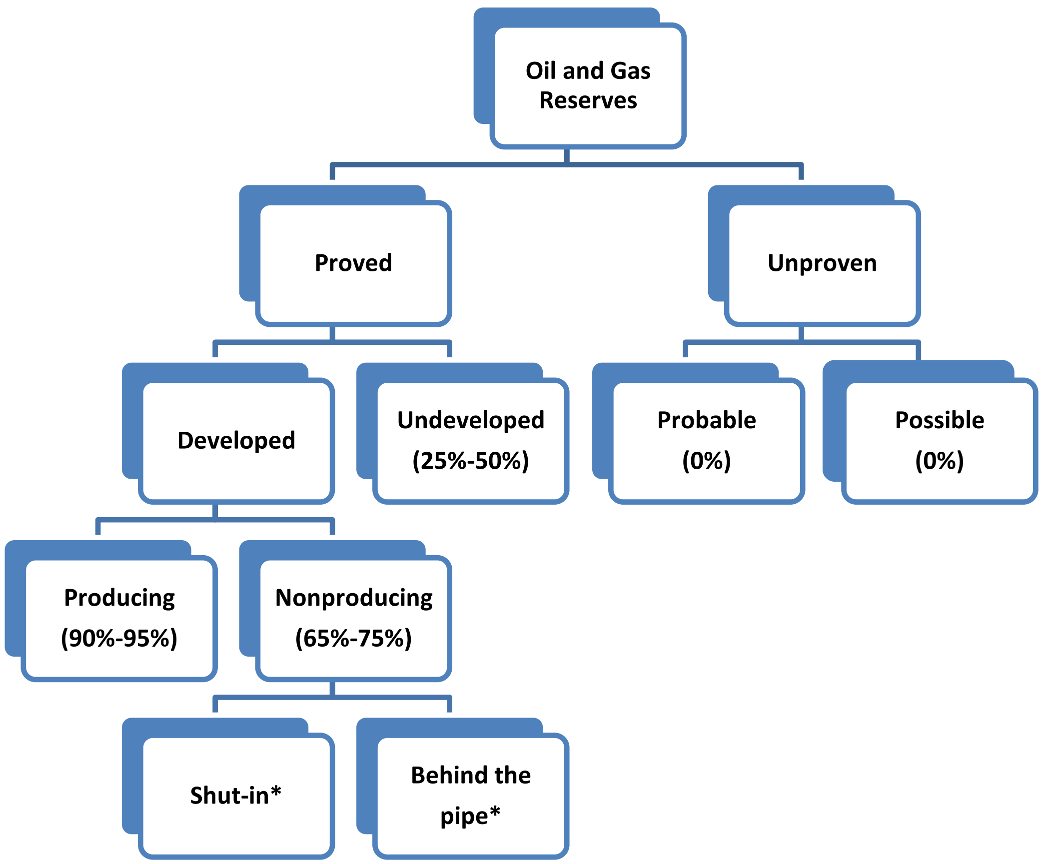

Table 1. Summary Statistics

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. The sample covers 69 oil producers that spud a total of 3,557 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 the quarterly earnings before interest taxes depreciation and amortization scaled by lagged assets. Assets is total assets, and Tobin's q is the market value of equity plus debt divided by book assets. The financials are as of the last quarter prior to onset of contango (September 2014). Panel B compares the low leverage (bottom four quintiles of market leverage ratio) and high leverage (top quintile) firms. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

Panel A: Full Sample Summary Statistics

Dependent variable	*N*	Mean	Std. Dev.	p25	p50	p75
Months from Project Start to Completion	3557	4.58	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	0.23	0.62	0.39***
Profitability (Q3 2014)	0.04	0.04	0.00
Size (assets in $millions)	36,780	3,978	-32,802
Tobin's q	1.24	0.86	-0.38***

Table 2: Leverage and Production Decisions, Univariate Test

This table reports the average number of months to complete a well after it is spud (started). Specifically, the columns report the average number of months wells sit idle prior to completion across different leverage thresholds. The "Super Contango" sample contains wells spudded during September, October, and November of 2014, and completed during the "Super Contango" period in December 2014 and early 2015. The "Pre-super Contango" sample contains wells spudded during September, October, and November of 2013 and completed in December 2013 and early 2014, this period forms the pre-event control period. The table reports the average number of months firms wait to complete wells in each period by quintiles of firms' market leverage. For each leverage quintile we report the difference in completion time across the two time periods. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Super Contango	Pre-super Contango	Difference
Leverage Quintile 5 (Highest Leverage)	3.75	3.57	-0.18
Leverage Quintile 4	5.31	3.64	-1.67***
Leverage Quintile 3	5.13	4.05	-1.08***
Leverage Quintile 2	4.92	4.20	-0.72***
Leverage Quintile 1 (Lowest Leverage)	5.06	4.05	-1.01***

Table 3: Differences in Investment Opportunities

This table provides project level comparisons of well costs and initial production volumes across both high leverage and low leverage firms. High-leverage firms are defined as those in the top 20% of the market leverage distribution. The remainder of the firm population is defined as low-leverage firms. Panel A reports univariate analysis of well characteristics, while Panel B reports the results of the regression analysis 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, 2014, and 2015. The Oklahoma Corporation Commission offers the broadest available data set that captures both well costs and initial production. These data overlap with the sample used in the main tests of this study, but only covers wells located in Oklahoma. The unit of observation is well j in year t. The regression specification includes both time and township-level geographic fixed effects (no well is farther than 8.48 miles from another well in a given township). In Panel B, the standard errors are clustered by firm and are reported in square 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	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 reports the results of a difference-in-difference analysis that evaluates 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 the date a well is spud (started) and the date when it is completed and production begins. 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 collateral-based lines of credit. The regression specifications include firm and township (geography) fixed effects. Standard errors reported in parenthesis are clustered at firm level. * 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)
$Contango_t$	1.090***	1.077***	1.093***	0.136***	0.159***	0.161***
	(0.331)	(0.210)	(0.210)	(0.040)	(0.032)	(0.032)
$Contango_t$ × Leverage p20 p40 D_i	-0.276			-0.012		
	(0.631)			(0.100)		
$Contango_t$ × Leverage p40 p60 D_i	0.147			0.065		
	(0.553)			(0.072)		
$Contango_t$ × Leverage p60 p80 D_i	0.184			0.054		
	(0.428)			(0.064)		
$Contango_t$ × Leverage p80 and up D_i	-1.014**	-1.002**		-0.119**	-0.142**	
	(0.442)	(0.383)		(0.058)	(0.054)	
$Contango_t$ × Asset Based Lending Leverage p80 and up D_i			-1.198***			-0.164***
			(0.320)			(0.048)
$FirmFE_i$	Yes	Yes	Yes	Yes	Yes	Yes
6 Sq Mile Geog FE	Yes	Yes	Yes	Yes	Yes	Yes
N	3557	3557	3557	3557	3557	3557
R^2	0.54	0.54	0.54	0.56	0.56	0.56

Table 5: Production Decisions and Debt Renegotiations, Univariate Tests

The table reports the results of univariate analysis that compares firms' well completion rates around debt renegotiation dates. The sample contains wells of firms with asset based lending and with borrowing base collateral redeterminations scheduled during February, March, April, and May of 2015. The unit of observation is well j for firm i in month t. The variable of interest equals one if production was initiated in a given month and zero otherwise for months before and after completion. Therefore the statistics reported can be interpreted as the share of spudded wells that were completed in a given month. High leverage firms are firms in the top quintile of the market leverage distribution as of September 2014, the last quarter prior to the beginning of the super-contango period. * 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	0.25	0.18	0.22	0.09	0.09	0.04	0.04	0.13***
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	0.013

Table 6: Production Decisions and Debt Renegotiations

The table reports the results of a regression form of difference-in-differences that compares firms' well completion rates around debt renegotiation dates. The sample contains wells of firms with asset based lending and with borrowing base collateral redeterminations scheduled during February, March, April, and May of 2015. The unit of observation is well j for firm i in month t. The dependent variable equals one if production was initiated in that month and zero otherwise for months before and after completion. The coefficients of the renegotiation dummies can be interpreted changes in well completion behavior relative to the omitted category (time t = -3). A negative coefficient can be interpreted as a relative decline in completion activity. Month = 0 is the month of the credit agreement renegotiation. All regressions include firms that are not subject to credit renegotiations as part of the control group. This control group is designed to control for general time trends in completion activity over this period. The direct effect of the high leverage dummy is absorbed by the firm fixed effects. Standard errors reported in brackets are clustered at firm level. * 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	0.020
	[0.061]	[0.039]	[0.038]
Month=-1 to Renegotiation D_t	-0.022	-0.007	-0.003
	[0.049]	[0.031]	[0.030]
Month=0 to Renegotiation D_t	-0.135**	-0.006	-0.005
	[0.050]	[0.037]	[0.036]
Month=1 to Renegotiation D_t	-0.107**	-0.034	-0.034
	[0.046]	[0.030]	[0.029]
Month=2 to Renegotiation D_t	-0.111***	-0.015	-0.014
	[0.037]	[0.031]	[0.031]
Month≥3+ to Renegotiation D_t	-0.092*	0.074	0.074
	[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			-0.010
			[0.054]
High $Leverage_i$ × Month=0 to Renegotiation D_t			-0.122**
			[0.057]
High $Leverage_i$ × Month=1 to Renegotiation D_t			-0.060
			[0.047]
High $Leverage_i$ × Month=2 to Renegotiation D_t			-0.090**
			[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	20,297
R^2	0.056	0.049	0.052

Table 7: Robustness Tests

This table reports results of a difference-in-difference analysis that evaluates whether other firm characteristics, in addition to leverage, affect well completion timing. The unit of observation is at the well j, firm i, year t level. The dependent variable is the number of months between the date a well is spud (started) and the date when it is completed and production begins. $Contango_t$ = 1 for wells spudded in September, October, and November of 2014. $Contango_t$ = 0 for wells spudded in September, October, and November of 2013. The firms' financial characteristics are compiled following Table 1. The direct effect of firm financial characteristics is absorbed by firm fixed effects. The regression specifications include township-level geographic fixed effects. Standard errors reported in parenthesis are clustered at firm level. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Dependent Variable = Months to Production			
	(1)	(2)	(3)	(4)
$Contango_t$	0.589	2.288*	0.786	1.594
	(0.541)	(1.192)	(0.588)	(1.239)
$Contango_t$ × High-leverage Dummy	-0.921**	-1.225***	-0.907**	-1.111**
	(0.399)	(0.391)	(0.429)	(0.431)
$Contango_t$ × $Profitability_i$	10.827			8.930
	(10.130)			(13.552)
$Contango_t$ × Log $Assets_i$		-0.121		-0.087
		(0.121)		(0.112)
$Contango_t$ × Tobin's Q_i			0.234	-0.041
			(0.423)	(0.543)
$FirmFE_i$	Yes	Yes	Yes	Yes
6 Sq Mile Geog FE	Yes	Yes	Yes	Yes
N	3,557	3,557	3,557	3,557
R^2	0.54	0.54	0.54	0.54

Table 8: Well Initial Production Before vs. After Debt Renegotiation

This table reports the univariate analysis of well-level initial production across high-leverage firms before and after debt renegotiation. Data on initial production from wells was collected from a subsample of firms which have operations in Texas (available through the Texas Railroad Commission) and in Oklahoma (available through the Oklahoma Corporation Commission). * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	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
High Leverage Firms	5.57	5.23	0.34*
N	151	41	

Table 9: High Collateral Impact vs. Low Collateral Impact, Univariate Tests

This table reports univariate analysis similar to that reported in Table 5. Panel A, reports the results for high-collateral-impact single well lease completion rates. The sample of high collateral impact wells contains wells on leases that have no other completed and producing well as of September 2014. In contrast, Panel B reports the results for low-collateral-impact multi-well leases. In this analysis the samples contain spudded wells located on leases with other completed and producing wells as of September 2014. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Well Starting Production Dummy Time 0 = month of debt renegotiation							Difference Well Starts$_{t=-1}$ - Well Starts$_{t=0}$
	-3	-2	-1	0	1	2	3+	
Panel A: Single Well Lease (High Collateral Impact)								
High Leverage	0.29	0.18	0.26	0.09	0.09	0.05	0.03	0.18***
Low Leverage	0.14	0.16	0.12	0.09	0.04	0.05	0.13	0.03
							Difference$_{High}$ - Difference$_{Low}$	0.15***
							p-value	0.002

	Well Starting Production Dummy Time 0 = month of debt renegotiation							Difference Well Starts$_{t=-1}$ - Well Starts$_{t=0}$
	-3	-2	-1	0	1	2	3+	
Panel B: Multi Well Lease (Low Collateral Impact)								
High Leverage	0.17	0.18	0.15	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**
							Difference$_{High}$ - Difference$_{Low}$	-0.01
							p-value	0.891

Table 10: High Collateral Impact vs. Low Collateral Impact

The table reports the results of a regression form of difference-in-differences for of completion activity of wells around credit agreement renegotiations for high collateral impact (single lease wells) and low collateral impact (multi-lease wells). The sample contains wells of firms with asset based lending and with borrowing base collateral redeterminations scheduled during February, March, April, and May of 2015. The unit of observation is well j for firm i in month t. The dependent variable equals one if production was initiated in that month and zero otherwise, including months before and after completion. The coefficients of the renegotiation dummies can be interpreted changes in well completion behavior relative to the omitted category (time t = -3). A negative coefficient can be interpreted as a relative decline in completion activity. Month = 0 is the month of the credit agreement renegotiation. All regressions include firms that are not subject to credit renegotiations as part of the control group. This control group is designed to control for general time trends in completion activity over this period. The direct effect of the high leverage dummy is absorbed by the firm fixed effects. Standard errors reported in brackets are clustered at firm level. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level. The regression controls for firm, time, and geography fixed effects. Standard errors reported in parenthesis are clustered at firm level. * 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 Collateral Impact			Low Collateral Impact		
	High Leverage	Low Leverage	All	High Leverage	Low Leverage	All
	(1)	(2)	(3)			
Month=-2 to Renegotiation D_t	-0.124	0.019	0.023	0.029	0.020	0.020
	[0.079]	[0.045]	[0.044]	[0.083]	[0.055]	[0.054]
Month=-1 to Renegotiation D_t	-0.046	-0.010	-0.004	0.004	0.011	0.012
	[0.096]	[0.041]	[0.041]	[0.062]	[0.043]	[0.043]
Month=0 to Renegotiation D_t	-0.213***	0.006	0.011	-0.020	0.000	-0.003
	[0.071]	[0.054]	[0.054]	[0.061]	[0.042]	[0.041]
Month=1 to Renegotiation D_t	-0.182***	-0.026	-0.023	-0.002	-0.026	-0.030
	[0.061]	[0.042]	[0.041]	[0.053]	[0.033]	[0.033]
Month=2 to Renegotiation D_t	-0.179***	0.014	0.016	-0.017	-0.027	-0.027
	[0.054]	[0.049]	[0.049]	[0.048]	[0.029]	[0.029]
Month≥3+ to Renegotiation D_t	-0.187***	0.106	0.106	0.048	0.059	0.059
	[0.061]	[0.065]	[0.064]	[0.057]	[0.055]	[0.055]
High Leverage$_i$ × Month=-2 to Renegotiation D_t			-0.144			0.013
			[0.090]			[0.097]
High Leverage$_i$ × Month=-1 to Renegotiation D_t			-0.035			-0.001
			[0.104]			[0.072]
High Leverage$_i$ × Month=0 to Renegotiation D_t			-0.211**			-0.013
			[0.084]			[0.068]
High Leverage$_i$ × Month=1 to Renegotiation D_t			-0.146**			0.041
			[0.067]			[0.053]
High Leverage$_i$ × Month=2 to Renegotiation D_t			-0.188***			0.018
			[0.067]			[0.046]
High Leverage$_i$ × Month≥3+ to Renegotiation D_t			-0.288***			-0.009
			[0.083]			[0.074]
FirmFE$_i$	Yes	Yes	Yes	Yes	Yes	Yes
MonthFE$_t$	Yes	Yes	Yes	Yes	Yes	Yes
6 Sq Mile Geog FE$_j$	Yes	Yes	Yes	Yes	Yes	Yes
N	8868	10194	11160	6183	8561	9137
R^2	0.052	0.040	0.046	0.075	0.071	0.071