The Real Effects of Covenants on Investment Productivity

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Abstract

How do firms adjust project-level operations in response to covenants? I test the real effects of a borrowing-base covenant in the oil and gas industry. In this industry, a borrowing-base covenant uses the expected cash flows from the quantities of subsurface oil and gas to set the firm's credit limit, collateralizes the loan with these quantities, and allows lenders to frequently review the collateral. I show that firms with borrowing-base covenants have higher five-year cumulative oil production, have greater maximum production rates, produce oil more efficiently relative to maximum production rates, and more quickly replace subsurface oil compared to firms without such covenants. The empirical findings suggest that this covenant relies on an investment feedback mechanism: it encourages firms to drill high-quality wells by offering investment funding for productivity and by magnifying the opportunity costs of failing to drill productive wells.

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1 Introduction

Collateral partially protects lenders and allows smaller, riskier borrowers to have access to credit (Benmelech et al., 2019). If collateral values covary with cash flows, though, sharp decreases in collateral value accompany a decreased probability of loan repayment. This correlation can lead to lenders seizing collateral when the collateral has the least value (Shleifer and Vishny, 1992). Especially in an incomplete contract setting, lenders would prefer to obviate this outcome by monitoring the value of the collateral and correspondingly updating the borrower's debt limit. A ubiquitous covenant in the oil and gas industry, called a borrowing-base covenant, grants lenders those rights.

In this study, I test whether the borrowing-base covenant influences capital expenditures and the operational performance of individual oil wells. Borrowing-base covenants are frequently attached to revolving credit facilities and permit lenders to adjust the limits of the revolving credit facilities twice per year. It combines features of cash-flow-based and asset-based lending, because the expected cash flows from the firm's oil and gas influence the limit of the revolving credit facility while the subsurface oil and gas serve as collateral for the loan.[1] Revolving credit facilities are critical funding sources for borrowing-base firms, so these firms must maintain access to the facilities for future investment.[2]

Previous studies have focused on the relationship between covenants and gross measures of investment, both before potential covenant violations and after technical violations. As firms approach covenant thresholds and the probability of violation increases, firms refrain from leverage increases even if the debt were intended for profitable projects (Cohen et al., 2019). When covenants are loosened, capital expenditures increase, but after a technical violation, capital expenditures decrease (Denis and Wang (2014), Chava and Roberts (2008)), and capital-expenditure restrictions contribute to a reduction in firm investment (Nini et al., 2009). However, the lack of project-level data has prevented inferences about the relation-

[1] See Section 2 for a fuller discussion of lending in the oil and gas industry.

[2] During the sample period, the borrowing-base statuses of firms were constant. Thus, referring to a firm subject to a borrowing-base covenant as a borrowing-base firm is accurate.

ship between covenants and the intensive margin of investment (i.e. project operational performance).

The oil and gas industry offers several advantages for providing a link between covenants and project operational performance. Investment opportunities likely differ among firms of various sizes across industries, so the endogenous nature of investment can restrict inferences (Gilje et al., 2017). Since the location, relevant dates, and operator of each well are included in well data, comparing wells in similar geographic and geologic conditions operated by different firms is possible. A fixed effects structure along with well-level controls–such as lateral length, months to production, and maximum one-month production rate–yields inferences at the well level.[3] Using a detailed dataset from WellDatabase, I find horizontal oil wells drilled in the continental United States by borrowing-base and non-borrowing-base firms from 2010-2013. This database gives the date that a well was drilled, the date that it first began producing oil, its geographic coordinates, the geological rock from which the well is producing oil, the horizontal length of the well, and the cumulative production of the well.

The identification strategy hinges on matching similar investments by different firms. The size, revolving credit facility utilization, and secured debt percentage, among other characteristics, are significantly different between borrowing-base and non-borrowing-base firms. Because borrowing-base and non-borrowing-base firms differ, matching on firm characteristics would not lead to meaningful inferences. Instead, I employ production, zip code, and geological rock fixed effects and include controls for common accounting measures and oil well characteristics. The vast majority of zip codes contain wells operated by both borrowing-base and non-borrowing-base firms, so concerns about incomparable investment opportunities are mitigated.

The key results concern the cumulative production of horizontal oil wells. In cross-sectional tests of five-year cumulative production, I find that borrowing-base firms produce

[3]The current study only uses horizontal oil wells. For horizontal wells, the lateral length is the length of the well that is drilled into the producing geological rock. In contrast, the vertical length is the height of the well from the surface to the beginning of the producing geological rock.

approximately 9% more oil than non-borrowing-base firms at the well level. The majority of this additional oil is captured during the first two years of a well's lifecycle, usually when the oil is the most valuable, and borrowing-base firms seem to accumulate this additional oil as a result of increased maximum oil rates. Further, the decline rates (the rate at which a well stops producing oil, measured as a given production rate scaled by the maximum rate) for wells operated by borrowing-base firms are less severe than those for non-borrowing-base firms. This result is consistent with borrowing-base firms drilling more productive wells in order to enhance or maintain their revolving credit facilities.

In Cohen et al. (2019), firms restrict their leverage as debt covenants approach their thresholds because of the potential negative consequences of violations. As borrowing-base firms approach their revolving credit limits, they are aware that future redeterminations could cut their limits. Further, if there were a credit decrease and the amount outstanding were higher than the new limit, these firms would have to repay the resulting deficiency likely at just the time that expected cash flows are low. Borrowing-base firms, therefore, need to replace their oil reserves at a sufficiently high rate to maintain or expand access to credit. Usually, adding reserves from extensions and improved recovery is cheaper than purchasing reserves from another firm, so borrowing-base firms should favor increasing reserves through organic methods rather than purchasing them. To test this conjecture, I run annual regressions of reserve replacement ratios on borrowing-base status and find that borrowing-base firms prefer to replace reserves through extensions and improvements.

In robustness tests for five-year cumulative oil production, I vary the distribution of well characteristics, the fixed effects, and size measurements. In additional robustness tests, I remove restrictions on well characteristics and increase the sample size. In all cross-sectional specifications, borrowing-base covenants are associated with higher cumulative oil production.

The empirical results suggest that the borrowing-base covenant offers a novel feedback mechanism through which firms can expand their credit supply and invest in future projects.

Because lenders estimate a well's total oil production by extrapolating the well's actual production, sustained higher production implies higher future production; further, the estimated quantity of subsurface oil and gas associated with such a well will be higher than the subsurface oil and gas associated with a lower-producing well. The expected cash flows from a higher-producing well will be higher, and, as long as the higher-producing well is representative of the subsurface oil and gas associated with current and future wells, the revolving credit facility limit will increase. With the increased revolving credit facility, the firm can drill wells on the remainder of its land positions. If, however, a borrowing-base firm waits to drill a productive well, it necessarily precludes current investment, exacerbating the opportunity costs of failing to invest (Rampini and Viswanathan, 2010). Therefore, the borrowing-base covenant encourages firms to drill productive wells by offering enhanced investment funding for productive wells and by magnifying the opportunity costs for failing to drill productive wells.

In conjunction with this investment feedback mechanism, the borrowing-base covenant utilizes secured debt and frequent monitoring. The subsurface oil and gas of a borrowing-base firm serve as the collateral for the revolving credit facility, and the lenders evaluate this collateral twice per year. During these redeterminations, lenders can increase, decrease, or maintain the revolving credit facility limit. While the secured debt and frequent monitoring relax the financial constraints of the borrowing-base firms, the combination also strengthens the control rights of lenders (e.g., Berger and Udell (1995), Benmelech et al. (2019)). The creditor's control rights reduce moral hazard problems and promote enhanced borrower effort, potentially leading to improved operating performance (Jensen (1986), Kaplan (1989), Boot et al. (1991), Guo et al. (2011)).

Thus, the borrowing-base covenant has two mechanisms operating simultaneously to promote higher capital expenditures and increased productivity while providing strong lender control rights. Borrowing-base firms maintain access to credit by drilling productive wells, but when collateral values decrease, lenders decrease revolving credit facilities to match the decreased future cash flows.

My findings contribute to the literature on the influence of covenants on a firm's operations and accounting decisions. Covenants can lower interest rates, generate more complete contracts and ease borrowers' financial constraints (Matvos, 2013), trigger future adjustments as borrowers' financial conditions change (e.g. Asquith et al. (2005)), and influence accounting choices (Beatty et al. (2002), Dichev and Skinner (2002)). Further, covenants feature prominently in explanations for renegotiations, especially in an incomplete contract framework (e.g. Sridhar and Magee (1997), Garleanu and Zwiebel (2008), Christensen et al. (2016), Nikolaev (2018)). Because the violation of covenants leads to the transfer of control rights to lenders (Beneish and Press, 1993), renegotiations can be costly and often modify covenants (Roberts, 2015). My results, by examining the investment feedback mechanism of the borrowing-base covenant, offer evidence of the link between a covenant and project-level performance. The fiindings are consistent with the borrowing-base covenant encouraging productivity and increasing the opportunity costs of failing to invest in high-quality projects.

Since the borrowing-base covenant includes the subsurface oil and gas as collateral, this study contributes to the literature on secured lending and incomplete contracting (Benmelech and Bergman (2008), Benmelech and Bergman (2009), Benmelech and Bergman (2011)). Bank monitoring of secured loans, especially when the value of collateral is likely to change, might explain the frequent redeterminations (Cerqueiro et al. (2016), Rajan and Winton (1995)). Further, because lenders frequently calculate the value of reserves by performing a discounted cash flow analysis using their own projections about future prices and costs, the borrowing-base covenant places precedence on relevance instead of reliability.

The remainder of the paper has the following organization. Section 2 provides an overview of the operations of the oil and gas industry, revolving credit facilities, and borrowing-base covenants. Section 3 develops hypotheses to be tested. Section 4 provides descriptive statistics for firm-level financials and well-level production. Section 5 presents the empirical analysis. Section 6 provides a robustness analysis for the empirical inferences. Finally, Section 7 concludes.

2 Overview of Oil and Gas Lending

2.1 Oil and Gas Industry Segments

The oil and gas industry comprises three segments: upstream, midstream, and downstream. Upstream activities include exploring for, developing, and producing oil and gas from geological formations; midstream activities include transporting and storing raw oil and gas; and downstream activities include refining, marketing, and distributing (Wright, 2017). The current paper concentrates on primarily upstream firms (sometimes called independents). These firms are most directly affected by oil and gas prices, and all other segments depend upon upstream activities.

2.2 Oil and Gas Reserves

For upstream firms, proved oil and gas reserves constitute the bulk of assets. Proved oil and gas reserves are those quantities of oil and gas that geoscience and engineering data indicate can be economically recovered with at least a 90% probability from a given date forward, from established reservoirs, under current economic conditions, and with established operating techniques (CFR, 2018). Proved reserves are further subcategorized into proved developed producing and proved undeveloped. Proved developed producing reserves are reserves from wells already drilled and with oil or gas flowing through the wellbore.[4] Proved undeveloped reserves require substantial investments before oil or gas can flow through the wellbore.

The other main category of oil and gas reserves is unproved reserves.[5] The SEC does not require that publicly traded firms report these reserves, and these reserves contribute little

[4]The wellbore is the actual hole in the ground that connects the reserves to the surface.

[5]Unproved reserves are further divided into two categories: probable and possible. Probable reserves have at least a 50% probability of recovery and possible reserves have at least a 10% probability of recovery.

value, if any, to lending agreements. The remainder of the paper focuses on proved reserves. Figure 1 presents a chart for the different categories and subcategories of reserves.[6]

2.3 Revolving Credit Facilities and Borrowing-Base Covenants

Revolving credit facilities (also known as revolving lines of credit, revolving credit agreements, and revolvers) are common for all exploration and production firms, and the firms consider these facilities as preferred liquidity sources.[7] Although some exploration and production firms have fully committed revolving credit facilities, most exploration and production firms have revolving credit facilities subject to borrowing-base covenants (also known as reserve-based revolving credit facilities). A borrowing-base covenant allows the lender to periodically (usually semi-annually) modify the amount of the revolving credit facility based on the lender's discretion and the value of the borrower's (proved) oil and gas reserves, and the borrower's oil and gas reserves typically serve as collateral for such a revolving credit facility. Revolving credit facilities, whether subject to a borrowing-base covenant or not, normally have senior priority.

The Office of the Comptroller of the Currency recommends that lending for revolving credit facilities with borrowing-base covenants be heavily reliant on proved developed producing reserves that have been producing for at least six months (Office of the Comptroller of the Currency, 2018). Lenders apply less weight to proved undeveloped reserves and less than six-month proved developed producing reserves.

The current paper distinguishes three different concepts to describe the available capacity of a revolving credit facility for borrowing-base firms: the borrowing base, the contractual limit, and the commitments. The borrowing base is a lender's valuation of a firm's oil and gas reserves based on the lender's predicted cash flows and the lender's discretion. The

[6] For the purposes of this study, proved developed non-producing reserves are not relevant.

[7] For example, Chesapeake Energy Corporation states in its 2012 10-K that it uses "these revolving bank credit facilities and cash on hand to fund daily operative activities and capital expenditures as needed." In addition, Abraxas Petroleum states in its 2011 10-K that "our primary sources of capital are availability under our credit facility and cash flow from operations."

contractual limit is the maximum amount that a revolving credit facility contract covers. (The borrowing base can be less than, equal to, or greater than the contractual limit.) Finally, the commitments are the minimum of the borrowing base and the contractual limit, and a firm can borrow up to the commitments on a revolving credit facility at any one time. Typically the commitments are equal to the borrowing base for borrowing-base firms, so the paper will often use the terms "borrowing base" and "commitments" interchangeably for these firms. For non-borrowing-base firms, the term "commitments" describes the capacity of the revolving credit agreement.

2.4 Production Decline Curve Analysis

Reservoir engineers extrapolate an oil well's current production to estimate the well's ultimate production of proved developed producing reserves. The basic methodology is the following: the natural logarithm of the monthly production rate is plotted against time and an exponential, harmonic, or hyperbolic curve is fitted to the data. Based on the type of decline curve, the engineer can project the future recoverable reserves from the well. Exponential declines lead to the greatest cumulative production while harmonic declines have the lowest cumulative production.

Hydraulically fractured horizontal oil wells usually have hyperbolic or harmonic declines, and the decline rates are influenced by the geological rock, the type of oil, completion parameters, and production style. Because of the decline curve analysis, higher production for a sustained period of time leads to a higher estimate of reserves for a well.

2.5 Illustrative Example

This subsection contains a simplified example of the procedure to determine the borrowing base of a revolving credit facility for those firms subject to a borrowing-base covenant. Suppose that a firm has performed decline curve analysis on its wells and reported the following: 75 proved developed producing reserves that have been producing for over 6 months (seasoned reserves), 15 proved developed producing reserves that have been producing for less than 6 months (unseasoned reserves), and 10 proved undeveloped reserves. The lender has projected the discounted price of the oil to be $10 per barrel, net of costs, for the life of the reserves. Further, the lender gives 100% weight for the seasoned reserves, 90% for the unseasoned reserves, and 50% for the proved undeveloped reserves. The risk-adjusted net present value of the reserves is $75 * 10 * 1.00 + 15 * 10 * .90 + 10 * 10 * .50 = \$935$. The lender then takes 80% of the net present value and determines the borrowing base to be $748.

As the example indicates, proved developed producing reserves are critical for borrowing-base firms. These firms want to convince lenders that each oil well contributes substantial proved developed producing reserves to the firm's inventory. There are two primary methods for doing so: 1) report a high initial production rate (especially for unseasoned reserves) and 2) produce sustained quantities of oil for at least six months.[8] Initial production rates are measured in barrels of oil per day and are based on firms' tests of productivity. There are no standards for how firms report the initial production rates, and different firms have different methods of testing the initial production rate. Because initial production rates are not measured uniformly across firms, this study does not address initial production rates.[9] Instead, this study examines cumulative production, because actual production is reported to state agencies.[10] Higher actual production for at least six months usually allows firms and lenders to perform more accurate decline curve analysis and estimate higher quantities of reserves for a given well, and a higher estimate of proved developed producing reserves increases the borrowing base.

[8]Horizontal shale oil wells experience substantial declines in oil production over the life of the well, so lenders do not expect to see a flat production curve.

[9]High initial production rates might still have positive impacts on the revolving credit facility limit. See Gilje et al. (2017) for tests on initial production rates.

[10]Oil and gas firms must report the actual quantities of oil and gas produced at the well, because states tax the output of each well.

3 Theoretical Development and Hypotheses

3.1 Theoretical Development

A borrowing-base covenant for a revolving credit facility comprises three economically significant instruments: secured debt, regular monitoring, and adjustment of the revolving credit facility limit. Debt has been hypothesized as a way to reduce agency costs and to improve operating performance (e.g. Jensen (1986) and Kaplan (1989)). The leveraged-buyout wave in the 1980s seemed to validate this view, but more recent research has questioned the magnitude of the operating performance improvements. Guo et al. (2011) find that, although there are greater increases in cash flow gains as leverage increases as a result of a buyout, the operating performance is substantially less than earlier claims. Further, Cohn et al. (2014) present evidence that the average leverage and operating performance are nearly constant before and after the buyout. Taken together, these studies provide some support that debt is a moderate, but insufficient, disciplinary mechanism on its own. For the types of firms subject to a borrowing-base covenant, solely increasing leverage would be unlikely to improve operating performance.

Adding security to debt strengthens the control function of unsecured debt. Collateral can alleviate some of the agency problems of moral hazard even though it imposes deadweight costs of repossession (Boot et al. (1991)). In addition, secured debt can be a potential solution to underinvestment, because it incentivizes the manger to undertake additional projects and work harder to increase the probability of project or business success (Stulz and Johnson (1985)).

However, collateral has costs for both borrowers and lenders. Borrowers lose financial and operational flexibility, and collateral is generally more valuable to borrowers than to lenders (Benmelech et al., 2019). If the success of the business is heavily dependent on industry-wide factors, managerial efforts could still lead to defaults. Any given oil and gas firm is unlikely to influence the prices of oil and gas (i.e. the oil and gas markets are competitive), so cash flows and the ability to repay debt are intimately tied to an industry-wide factor. Control rights would transfer to lenders in states of the world in which the collateral (i.e. oil and gas reserves) falls in value for all companies (Shleifer and Vishny, 1992). Further, unlike airplanes in Benmelech and Bergman (2008), oil and gas reserves are geographically fixed, so borrowers and lenders might not experience the benefits from high redeployability (Benmelech and Bergman, 2009).

In combination with secured debt, monitoring the collateral and adjusting the credit facility amount help lenders to keep an accurate valuation of the underlying collateral and seem to protect lenders while giving managers incentives to become more productive (Berger and Udell, 1995). A borrowing-base covenant employs these combined features with the expected cash flows from the oil and gas reserves as the primary determinant for the revolving credit facility limit and the oil and gas reserves as the facility's collateral. Although accounts receivable or another accounting measure is often the collateral for asset-based loans, the oil and gas industry has the factors of production (i.e. the oil and gas reserves) as the collateral. If a lender forecloses on a borrower's oil and gas reserves after a default, the effect is to cripple the oil and gas firm.

Because the volatility of oil and gas prices preclude Arrow-Debreu securities for every state of the world, lenders need a solution for the incompleteness. The borrowing-base covenant's combination of secured debt, monitoring, and adjustment of credit limits is likely a disciplinary mechanism for moral hazard in risky firms (i.e. those firms which are likely to default and file for bankruptcy).[11] Firms with a borrowing-base covenant have a higher opportunity cost of failing to invest in productive wells. The revolving credit facility capacity depends upon the value of the firm's reserves, so every missed productive well is a missed opportunity to increase the value of the reserves if prices and costs are held constant. When oil and gas prices are falling, productive wells can marginally mitigate the decrease in the revolving credit facility.

[11] Information asymmetry does not seem to be a compelling explanation, because borrowing-base and non-borrowing-base firms drill in approximately the same areas. See Figure 4.

Since the lenders usually evaluate the borrowing-base firm's oil and gas reserves biannually, the quality of past wells has an impact on future redeterminations. Poor-quality wells lead to little, if any, increase in reserve value while high-quality wells continue to positively contribute to reserve value during each subsequent redetermination. Compared to a non-borrowing-base firm's marginal well, therefore, a borrowing-base firm's marginal well has a more significant impact on access to credit.

The redetermination process prevents borrowing-base firms that expect to survive as a going-concern from squandering their revolving credit facilities. Although these firms must invest to maintain a crucial source of funding and their opportunity cost of failing to invest is high, they do not necessarily want to utilize 100% of their revolving credit facilities. If a borrowing-base firm reaches the capacity of its revolving credit facility and an unexpected drop in oil or gas prices decreases the value of the reserves below the previous capacity, the lender gives the borrower a short grace period to repay the deficiency; if the borrowing-base firm fails to rectify the deficiency, the borrower is in default. In states of the world in which the value of reserves declines, borrowing-base firms typically have little cash, so these firms must spend their cash paying down debt just as cash flow decreases.

Rampini and Viswanathan (2010), despite their use of Arrow-Debreu state-contingent securities, offer key intuition for the effect of collateral on productivity and investment in an incomplete contracting framework. The primary feature of Rampini and Viswanathan (2010) is the tradeoff between conserving debt capacity and investing immediately. Conserving debt capacity has an opportunity cost: current investment is forgone. When firms' production functions feature constant returns to scale but differ in productivity, the more productive firms have higher opportunity costs for failing to invest. This implies that the more productive firms exhaust their debt capacity in the current period and eschew risk management (hedging or conserving debt capacity). The borrowing-base covenant increases the opportunity cost of failing to invest in more productive wells. Missed wells and poor-quality wells likely fail to expand the revolving credit facility limit, so firms have fewer funds with which to invest than they otherwise would have had.

Although the typical maturity for a revolving credit facility is five years, the borrowing-base covenant is somewhat equivalent to a series of short-term loans. During every redetermination period, lenders decide whether to expand, maintain, or contract the revolving credit limit, and continued funding depends upon the truthful reporting of reserves and cash flows. In this equivalent environment, Bolton and Scharfstein (1990) suggests that lenders will match the debt amount to the expected cash flows and that borrowing-base firms will truthfully report reserves and expected cash flows. If a borrowing-base firm fails to keep the drawn amount below the limit of the revolving credit facility, the firm would default on the loan and the lender could liquidate (or at least initiate foreclosure proceedings for) the collateral.

3.2 Hypotheses

In the oil and gas industry, some firms are not subject to borrowing-base covenants, but the majority of borrowers are subject to these covenants. Borrowing-base firms differ from non-borrowing-base firms likely because of moral hazard, suggesting that borrowing-base firms are riskier before and after contract initiation. Lenders do not randomly assign borrowing-base covenants, so the presence of such a covenant is probably correlated with other characteristics of risk, and the borrowing-base covenant is an attempt to constrain firms and encourage prudent investment. According to Rampini and Viswanathan (2010), more constrained firms have lower net worth, rely more heavily on credit, and have higher leverage. Thus, the alternative hypothesis follows:

Hypothesis 1: Borrowing-base firms have fewer assets, higher non-revolving leverage, and higher credit utilization compared to non-borrowing-base firms.

Increased production in a well's early life can decrease the payback period, increase short-term cash flows, and possibly lead to higher valuations, but this increased production can have negative long-term effects on the ultimate recovery of oil; a difference of 3% of cumulative production, for example, could have an impact on the valuation of a firm's reserves (Shattuck, 2017). If borrowing-base firms are myopic and actively produce their wells too aggressively at the beginning of the wells' lifecycles, the long-term productivity of the wells might suffer. The cumulative production of oil wells would be greater in early stages but less over long periods than the cumulative production for non-borrowing-base firms. Reduced cumulative production would require a greater number of wells to be drilled and likely lead to higher costs. Such costs would be consistent with overproduction in a real earnings management framework (Roychowdhury (2006)).

Because the borrowing-base covenant adjusts the revolving credit facility to approximately the collateral value, the quality of oil reserves is the definitive factor for continued access to a revolving credit facility for borrowing-base firms. The revolving credit facilities of non-borrowing-base firms, however, do not fluctuate with the value of reserves. Although each type of firm has incentives to drill and produce high-quality wells, a preferred funding source for borrowing-base firms depends upon the production from the wells. Further, firms with committed revolving credit facilities have incentives to invest in more illiquid projects (Acharya et al., 2014). The implication is that borrowing-base firms are more productive per well. Shale oil wells[12] typically drain close to 75% of the estimated reserves in approximately five years (Vieth, 2017), so the lifespan of a well is considered sixty months in the current study. Thus, the null hypothesis follows:

Hypothesis 2: After controlling for drill date, first production date, geography, geology and well characteristics, five-year cumulative production amounts of oil for horizontal oil wells operated by borrowing-base firms are the same as those operated by non-borrowing-base firms.

[12]The current study only uses oil wells drilled into tight rocks. Often these wells are considered shale wells. These wells are horizontally drilled, and the rock is fractured to release the oil into the wellbore.

A crucial driver for cumulative oil production is the one-month maximum production rate.[13] This one-month maximum rate typically occurs during the second month of oil production and is controlled by the geological rock properties and the well completion procedures.[14] The majority of a horizontal oil well's costs come from well completion, so companies must balance the improved recoverability of oil from more expensive well completions against the increasing costs of such completions. If a borrowing-base firm invests a substantial amount into a well but the well does not recover economic quantities of oil, the borrowing-base firm suffers more than a non-borrowing-base firm. Alternatively, a group of highly productive and economic wells can increase the revolving credit facility limit. The null hypothesis follows:

Hypothesis 3: After controlling for drill date, first production date, geography, geology and well characteristics, one-month maximum production rates for horizontal oil wells operated by borrowing-base firms are the same as those operated by non-borrowing-base firms.

For borrowing-base firms, each additional investment is incrementally critically, because a failed oil well would contribute nothing to a lender's evaluation of a borrowing-base firm's collateral value. In addition, since producing oil depletes a firm's reserves, the collateral value of borrowing-base firms would naturally decrease over time if those reserves are not replaced. In contrast, the revolving credit facility of a non-borrowing-base firm would not immediately suffer from a marginally poor investment nor from the depletion of its reserves. This suggests that borrowing-base firms should replace their reserves at a higher rate compared to non-borrowing-base firms. Further, the manner in which borrowing-base

[13] The one-month maximum production rate is calculated by dividing the cumulative monthly oil amount for the month with highest production by the number of days during that month.

[14] Well completion for horizontal oil wells involves perforating the geological rock, injecting large volumes of chemicals and water in the well under pressure to create additional fractures, and forcing sand particles into those fractures to allow oil to flow into the wellbore.

firms replace their reserves would likely differ, because borrowing-base firms do not have the capital to continually purchase reserves. Typically, the most efficient method is organic replacement (extending drilling from existing known reserves and improving the recovery of reserves from previously drilled wells). Thus, the alternative hypothesis follows:

Hypothesis 4: Borrowing-base firms replace their reserves at higher rates compared to non-borrowing-base firms, and the preferred method is organic reserve replacement.

4 Data and Summary Statistics

4.1 Sample Construction

I focus on the oil and gas industry because of the borrowing base's prevalence in the industry and the availability of project-level data for each firm. Since the shale oil boom began increasing oil production around 2008 and because the financial crisis of 2007-2009 had a dramatic impact on oil and gas prices, the sample period begins in the second quarter of 2010. The primary outcome variable is the amount of oil produced over five years, and the sample period runs from the second quarter of 2010 through the fourth quarter of 2013.

To identify exploration and production companies, I use the following procedure. First, I filter firms from Compustat and CRSP with SIC codes 1310, 1311, 1321, 1381, or 1382, and I require that the firms have headquarters in the US or Canada. Second, I eliminate all firms that did not trade on the NYSE, NASDAQ, or NYSE MKT. Third, I obtain the remaining firms' CIK codes and remove any firm-quarters in a year in which a firm did not file a 10-K. Fourth, I drop firms without drilling and operating activities in the US. Finally, I manually check each firm's primary business purpose from a firm's 10-K, and I keep only those firms whose objectives are exploration and production. This procedure eliminates midstream and downstream firms, integrated firms, and solely international firms.

Classifying the borrowing base and secured statuses of the revolving lines of credit is critical for this study. Regulation S-K requires firms to discuss their liquidity in the Management Discussion and Analysis (MD&A) section of 10-Qs and 10-Ks, and exploration and production firms usually discuss their revolving lines of credit in the MD&A and give additional information in a financial statement note on debt. I obtain from 10-Ks whether the revolving line of credit has a borrowing-base covenant and whether the revolving line of credit is secured by a firm's reserves.

For information about financial characteristics of the lines of credit, I collect information from Capital IQ. Capital IQ searches the MD&As, footnotes, and notes to the financial statements and provides information on debt structure, including the drawn and undrawn portions of the lines of credit. However, Capital IQ's information on the undrawn amount of the line of credit is not always reliable in the fourth quarter. I remedy this deficiency by doing the following: I assume that the total commitments in the fourth quarter are the same as those in the subsequent first quarter.[15]

For firm financials and detailed information on oil and gas reserves, I also use Capital IQ. Exploration and production firms must annually report the quantity of oil and gas reserves, and these firms must perform a discounted cash-flow analysis based on these reserves.

WellDatabase aggregates well drilling, completions, and production data from all US government providers. This database contains nearly every well drilled and produced in the United States since 1860. The well data includes the following relevant information: well coordinates, operator, county, state, drilling date, completions date, first production date, initial production rates, and cumulative amounts of oil over several time horizons. I create a linking table to match the CapitalIQ firm names with the operating firms. I also verify the WellDatabase data with oil well data from National Oil and Gas Gateway.[16]

[15] Because the revolving credit facilities are redetermined during the spring and fall, many redeterminations occur during the second and fourth quarters. Therefore, as an approximation, a revolving credit facility has the same commitments during the second and third quarters and then during the fourth and subsequent first quarters

[16] National Oil and Gas Gateway is a free, publicly available database of oil and gas wells located in 11 states.

4.2 Firm, Revolving Credit, and Investment Characteristics

I obtain quarterly financial information for 76 firms that meet the above criteria. Panels A and B provide the financial summary statistics for non-borrowing-base and borrowing-base firms, respectively. Non-borrowing-base firms are vastly bigger and more profitable, suggesting that size and profitability are important factors in the assignment of the borrowing-base covenant (Flannery and Wang, 2011). The mean Size for non-borrowing-base firms is \$21,039 million and for borrowing-base firms \$3,139. As the size distribution indicates, the top 25% of borrowing-base firm-quarter observations are most similar to the bottom 25% of non-borrowing-base firm-quarter observations. Borrowing-base firms have higher non-revolving leverage, higher revolving credit utilization, lower ROA, and lower commitments than non-borrowing-base firms.

The ratios Revolving-to-Debt and Revolving-to-Secured demonstrate the importance of revolving credit facilities for borrowing-base firms. Non-borrowing-base firms rarely secure their revolving credit facilities by oil and gas reserves, and therefore they have a smaller percentage of secured debt from these facilities (mean: 4%, median: 0%). Borrowing-base firms, however, almost always secured their revolving credit facilities by oil and gas reserves. Because of this collateral provision, borrowing-base firms have a substantial percentage of secured debt from their revolving facilities (mean: 64%, median: 99%). Further, for borrowing-base firms, the mean (median) percentage of total debt from revolving facilities is 32% (19%), while non-borrowing-base firms have a mean (median) percentage of total debt from revolving facilities of 8% (0%).

Because of the stark differences in firm financials, the empirical tests in Section 5 do not yield causal inferences. The regression results supply associations between the dependent variables, and the associations can be consistent with the economic forces discussed in Section 3. In addition, since the shale oil boom began a couple years before the start of the sample period, the empirical findings are early evidence of the cumulative production of these wells and the behavior of borrowing-base and non-borrowing-base firms.

Figure 2 displays the annual aggregate commitments of revolving credit facilities for borrowing-base and non-borrowing-base firms. From 2010 through 2013, the aggregate commitments increased for both types of firms, and at the end of 2013 the commitments totaled approximately $100 billion, split evenly between both groups.

Table 2 supplies the correlation table for the financial variables. Because the primary assets of oil and gas firms are reserves and reserves are correlated with revolving line commitments, Size is highly correlated with Commitments. Also, Size is negatively correlated with Credit Utilization, Revolving-to-Debt, and Revolving-to-Secured. These relationships are consistent with larger firms relying less on their (unsecured) revolving credit facilities. Importantly, Credit Utilization and non-revolving Leverage are not perfectly correlated, implying that these variables are not interchangeable. In fact, the negative correlation suggests that there is a partial substitution between these types of credit. The borrowing-base covenant, therefore, likely affects firm behavior differently than non-revolving leverage by itself.

Table 3 provides production summary statistics at the well level. Panel A presents production summary statistics for oil wells for non-borrowing-base and borrowing-base firms. Although approximately 70% of the firm-quarter observations from Table 1 come from borrowing-base firms, non-borrowing-base firms and borrowing-base firms drilled and completed approximately the same number of total wells.The distributions for $FiveYearOil$ and $MaxRate$ indicate that there is a substantial range in outcomes, and this is consistent with geographic and geological variations critically influencing production. Panel B displays the residualized differences between the well characteristics for non-borrowing-base and borrowing-base firms. To compute the residuals, I regress the variables on the production year-quarter and zip code-geological rock fixed effects. The month of the maximum one-month rate, the lateral length, and the months from the initiation of drilling to production do not significantly differ between the two types of firms.

In the production tests, the primary outcome variable is the cumulative five-year oil amount, because wells have produced the vast majority of extractable oil after five years. The production rate declines rapidly for horizontal oil wells compared to traditional vertical wells. As Figure 3 displays, the production rate for horizontal wells drops after the maximum one-month rate (usually in the second or third month of production) and is approximately 8% of the maximum rate by five years. Further, Figure 3 suggests that borrowing-base firms produce at a higher percentage of a well's maximum rate.

For the main tests, I require that the horizontal length of the well be between 3,000 and 15,500 feet, the time between drilling and initiation of production be less than three years, the month of maximum oil occur within the first six months of production, and the geological rock must have at least ten wells drilled into it. These restrictions leave 16,697 wells for the main tests. In some robustness tests, I drop these restrictions and use all 21,517 wells that were matched to firms in my sample.

5 Empirical Analysis

5.1 Production

5.1.1 Identification Strategy

The financial differences between borrowing-base and non-borrowing-base firms precludes treating the borrowing-base covenant as randomly assigned. Attempting to match on firm characteristics would likely give misleading inferences, because the matched firms would be representative of neither borrowing-base nor non-borrowing-base firms. In addition, since the primary outcome variable is on a project level, matching on firm characteristics and controlling for project characteristics would nearly require a randomized control trial.

Instead of matching on firm characteristics, the intuition behind the identification strategy is matching on projects. I consider each horizontal well a project, and I include fixed effects for the geographic zip code, the geological rock into which the well is drilled, and the year-quarter of production. A geographic zip code fixed effect controls for surface conditions, such as proximity to roads, pipeline access, and land prices. The geological rock is the primary determinant of oil production. The interaction of zip code and geological rock captures the variation in the rock over geographic distances.[17] The year-quarter of production controls for the economic conditions at the time of production. Although different geological rocks have different costs and production, the oil spot and futures prices roughly apply on a national level.[18] Therefore, the economic conditions during the production year-quarters are similar across the United States.

5.1.2 Analysis

To test Hypothesis 2, I need similar investment opportunities on a project level. As discussed in Section 5.1.1, oil well data is sufficiently detailed to compare similar projects. I exploit the rich micro-level information for oil wells and develop a fixed-effect framework to compare within-zip code wells. The fixed effects allow comparison of wells in the same zip code, horizontally drilled into the same rock, and first producing in a given year-quarter. The fixed-effect model follows:

$$LnProd_{j,i,t,r} = \beta BB_i + \pi'\Pi_{i,t-1} + \gamma'\Gamma_{j,t} + \theta_r + \delta_t + \varepsilon_{j,i,t,r,p} \tag{1}$$

The variable of interest is BB, and, as the subscript implies, this is a firm characteristic during the sample period. $Prod_{j,i,t,r,p}$ is a measure of oil production for well j by firm i horizontally drilled into geological rock-county r with first production in year-quarter t. The

[17] The vast majority of wells are located in zip code tabulation areas. For those wells that are not located in a zip code tabulation area, I assign the well to the zip code with the minimum distance to the centroid of the zip code tabulation area. A common surface measure in the oil and gas industry is a township-range, which is a 36 mi^2 square divided into 1 mi^2 areas. However, Texas does not have townships throughout the state, so I use zip codes to compare nearby wells.

[18] Realized natural gas prices are extensively impacted by regional characteristics, because the natural gas transportation infrastructure is much less developed than the oil transportation infrastructure.

main production outcome measure is five-year cumulative production.[19] Π is a vector of financial control variables, and Γ is a vector of well characteristics. Π includes controls for size, credit usage, non-revolving leverage, ability to service debt, cash-on-hand, profitability, growth, and accounting choice. Γ includes the lateral length of the well, the months from drilling until first production, the maximum one-month rate, the first month's ratio of natural gas to oil, and the first month's ratio of water to oil.[20] θ_r is a fixed effect for the zip code-geological rock in which the well is located. Since firms might drill into different rocks within the same zip code, the zip code-rock fixed effect ensures that similar investments are compared. δ_t is a fixed effect for the year-quarter of first production, because the year-quarter of first production encompasses the economic environment and the advancement in technology at that time. Standard errors are clustered by firm.

Π includes the following: $LnSize$, the natural logarithm of net property, plant, and equipment; $CreditUtil$, the drawn portion of the revolving credit facility scaled by the capacity of the facility; $NonRevLeverage$, non-revolving debt scaled by total assets; *Debt-to-*$EBITDA5$, an indicator which equals one if total debt divided by trailing twelve-month EBITDA is greater than 5;[21] $EBITDA$*-to-Interest*2, an indicator which equals one if EBITDA divided by interest expenses is less than two; $CurrRatio1$, an indicator that equals one if the current ratio is less than one; $CSTI$, cash and short-term investments scaled by net property, plant, and equipment; ROA, net income in period t scaled by net property, plant, and equipment from period t-1, similar to the ROA measure in Kothari et al. (2005); $Growth$, the quarterly percentage increase or decrease in net property, plant, and equipment; and $FullCost$, an indicator that equals one if the firm uses full-cost accounting to value net property, plant, and equipment. Γ includes the following: $LnLateralLength$, the length of the horizontal

[19]When $MaxRate$ is included as a covariate, the month of highest oil production is subtracted from the total cumulative production. Although $MaxRate$ heavily influences five-year cumulative production, the process is not deterministic.

[20]Horizontal oil wells usually peak in the first full month of production, which is often the second month of production.

[21]Debt scaled by EBITDAX, which is EBITDA plus exploration expenses, is a common financial ratio in the oil and gas industry. However, exploration expenses are only reported on an annual basis, so EBITDA is an imperfect quarterly proxy for EBITDAX.

section of the wellbore;[22] $LnMonthToProd$, the number of months from the initiation of drilling to first production; $LnMaxRate$, the natural logarithm of the one-month maximum oil rate; $FirstMonthGOR$, the first production month's ratio of natural gas to oil; and $FirstMonthWOR$, the first production month's ratio of water to oil.

Many of the control variables are scaled by net property, plant, and equipment, because including the drawn part of a revolving credit facility mechanically affects assets without accurately representing the size of a firm (Sufi, 2009). $LnSize$ is the historical asset size of oil and gas reserves after subtracting depreciation, amortization, and depletion. For oil and gas firms, net property, plant, and equipment represents the vast majority of assets and is therefore the control for firm size. $CreditUtil$ and $NonRevLeverage$ are lagged by one period since there can be time between drawing or raising funds and using those funds. $Debt\text{-}to\text{-}EBITDA5$, $EBITDA\text{-}to\text{-}Interest2$, and $CurrRatio1$ are included because borrowing-base revolving credit facilities and some non-borrowing-base revolving credit facilities attach these financial covenants to the facilities. ROA and $CSTI$ are controls for profitability and cash-on-hand, because these funds are preferred sources of financing in the oil and gas industry. $FullCost$ controls for the firm's choice to use full-cost accounting instead of successful efforts.[23] The well controls are included to compare similar wells in similar geological and geographical conditions.

All financial control variables are from the quarter before the quarter during which the well begins producing. Although many wells begin drilling and producing during the same quarter, sometimes drilling begins in one quarter while production begins in a subsequent quarter. The quarter before production begins is chosen, because the costs for production are approximately 60-70% of total wells costs. After production is initiated for a horizontal well, stopping the flow of oil is costly. Further, drilling and producing can be viewed as a two-stage process, and production can be delayed after the wellbore is drilled but before it

[22] The horizontal section is the portion of the wellbore that is drilled into the rock from which oil flows

[23] Full-cost accounting allows a firm to capitalize all exploration costs while the successful efforts method only allows exploration costs to be capitalized when oil or gas is found.

is completed (Kellogg (2014); Gilje et al. (2017)).

I estimate Equation (1) with five-year cumulative oil production as the primary outcome variable, and Table 4 presents the results. Column (1) includes only four financial covariates, and Column (2) includes all financial covariates. Finally, Column (3) contains all financial and well controls. Each regression model has an adjusted R^2 of approximately .69 to .88, implying that the models describe a large proportion of the variation in cumulative production and the fixed effects are especially important in explaining the variation. β_1 is statistically significant in Columns (1) - (3), and the value ranges from .094 to .182. These cross-sectional regressions indicate that a borrowing-base firm is associated with a 10% increase in cumulative five-year production within a zip code-rock unit.[24] These results are consistent with the borrowing-base covenant encouraging more productive wells, but the deterministic assignment of the borrowing-base covenant prevents causal claims.

As expected, the lateral length of a well and the maximum one-month rate are highly statistically significant. A 1% increase in lateral length leads to an approximately .25% increase in five-year cumulative production within a zip code-rock, while a 1% increase in maximum one-month production leads to an approximately .90% increase in five-year cumulative production.[25] If all else is equal, a longer lateral length and a higher maximum one-month rate require more capital expenditures, because the drilling process takes longer and the production process is more extensive. Therefore, even though the cost of the wells is not included in the regressions, lateral length and maximum one-month production rate are likely correlated with costs.[26]

To determine the timing of the increased five-year cumulative oil production, I examine cumulative oil production over one-year, two-year, three-year, and four-year periods. Table 5 contains the results of the regressions. The cumulative oil builds during the first two years

[24] $e^{.094} - 1 = .099$

[25] Because of the engineering processes used in drilling and producing oil, causal claims about lateral length and maximum one-month rate are supported.

[26] States usually do not collect nor distribute information on well costs. The State of Oklahoma collects drilling and production costs for some of its wells.

and then maintains that level throughout the five years of the oil for borrowing-base firms.

One potential concern with including $MaxRate$ as a control in Equation 1 is that firms attempt to jointly determine the cumulative production and the maximum rate. Because firms can partially control the maximum rate with well completion procedures and the maximum rate influences but does not deterministically set the cumulative production, firms perform a joint analysis of these variables. Tables 4 and Table 5 suggest that, after controlling for the potentially endogenous regressor, the results still hold. To analyze whether borrowing-base firms have systematically higher maximum production rates, I re-estimate 1 with $MaxRate$ as the dependent variable. Table 6 contains the results. Across all three columns, borrowing-base firms are associated with increased maximum rates.

The regressions in Tables 4, 5, and 6 suggest that borrowing-base firms produce more oil during the first two years of a well's life but that the production rates do not suffer by year five, and one of the explanations is the increased maximum rates. To determine whether the rates of production decrease for borrowing-base firms relative to the maximum rates, I examine decline rates. A decline rate is the production rate over a time period scaled by the maximum one-month production rate, yielding a percentage of the maximum rate. As Figure 3 shows, the decline rate from years three to five is approximately .08 for both types of firms. This decline rate implies that horizontal oil wells are producing at a small fraction of the maximum one-month rate. Table 7 contains the regressions for the decline rate regressions. For each examined period, borrowing-base firms produce at one to two percentage points higher than non-borrowing-base firms. The results are consistent with borrowing-base firms producing at a statistically significantly higher rate of the maximum one-month rate while not suffering decreased production near year five.

Although a borrowing-base covenant expands access to credit and lowers interest rates (Flannery and Wang, 2011) and is associated with higher productivity per well, firms seem to avoid the imposition of such covenants when possible. The primary reasons for doing so are the provision of collateral and the potential decrease in funding during oil price decreases.

Since the oil market is competitive, a sharp decrease in oil prices and the accompanying decrease in collateral value could, in the worst states, transfer control of a firm's factor of production to lenders. Higher productivity per well does not compensate for deadweight collateral costs and uncertainty of investment funding. In addition, larger firms likely have greater bargaining power, so they can obtain a borrowing-base-free loan from several lenders.

5.2 Reserve Replacement Ratios

Because oil and gas firms decrease their reserves as they produce oil and gas, they must continually replace the produced reserves. If the firms do not replace the reserves, those firms would cease operations as an oil and gas firm. Since borrowing-base firms must at least maintain reserve levels to access the same amount of credit (all else equal), borrowing-base firms need to quickly replace their reserves. If a non-borrowing-base firm does not replace its produced reserves immediately, its revolving credit facility will not suffer.The model for reserve replacement ratios follows:

5.2.1 Analysis

The model follows:

$$\begin{aligned} RRR_{i,t} = &\beta_1 BB_i + \beta_2 LnDCF_{i,t-1} + \beta_3 CreditUtil_{i,t} + \beta_4 NonRevLeverage_{i,t} + \\ &\beta_5 \textit{Debt-to-}EBITDAX5_{i,t-1} + \beta_6 EBITDAX\textit{-to-}Interest2_{i,t} + \beta_7 CurrRatio1_{i,t} + \\ &\beta_8 CSTI_{i,t} + \beta_9 ROA_{i,t} + \beta_{10} FullCost_i + \beta_{11} AvgPrcOil_{i,t} + \\ &\zeta_t + \varepsilon_{i,t} \end{aligned} \tag{2}$$

The dependent variables are reserve replacement ratios. Different reserve replacement ratios clarify the source of the new reserves, because some reserves are added through exploration and extensions while other reserves are added from purchases. The coefficient of interest is β_1. Except for $LnDCF$, the other control variables are similar to those in Equation 1. $LnDCF$ is the natural logarithm of the standardized measure of discounted cash flows. Each year, a firm must report its expected cash flows from its reserves using the arithmetic average of prices during the first-day of the previous twelve months. For the model in Equation 2, $LnDCF$ controls for size and projected value of the proved reserves, and the other covariates control for credit usage, non-revolving leverage, ability to service debt, cash-on-hand, profitability, growth, and accounting choice.

Table 8 contains the results from estimating Equation 2. The reserve replacement ratio in Column (1) is the organic reserve replacement ratio; it is the sum of reserves added by extension and by improved recovery scaled by total produced oil over the past year. Column (2) is the sum of organic reserves plus revisions scaled by total produced oil over the past year. Column (3) includes reserves added by extension, improved recovery, revisions, and purchases. Column (4) includes reserves added by the methods in Column (3) plus other adjustments. Across all four specifications, β_1 is significant, suggesting that borrowing-base firms prefer to replace reserves organically rather than by purchasing reserves.

6 Robustness

6.1 Cumulative Production

Table 9 contains various specifications to determine the robustness of the main cumulative production regressions. Column (1) removes the top and bottom 10% of maximum rates to ensure that outlying maximum results do not drive the results, and Columns (2) and (3) performs similar analyses with lateral lengths and cumulative oil production, respectively. The qualitative inferences from these regressions are the same as the main specification in Table 4. Borrowing-base wells are associated with approximately 7% higher cumulative oil production.

The specifications in Columns (4) through (6) change the fixed-effects structure, because the fixed effects explain the majority of the variation. In Column (4), a fixed effect for county-geological rock replaces the zip code-geological fixed effect. Column (5) replaces the zip code-geological rock fixed effect with a township-geological rock fixed effect in Texas. Column (6) includes a fixed effect for the triple interaction of production year-quarter, zip code, and geological rock. In Column (7), the production year-quarter fixed effect is interacted with the month of the maximum oil amount while keeping the zip code-geological rock fixed effect. The inferences and coefficients across these four specifications are similar to each other and to the inferences from the main specification.

Column (8) clusters standard errors by firm and geological rock. Rather than statistically significant at the 1% level as in the main specification, β_1 is statistically significant at the 5% level. Column (9) drops all restrictions on well controls and therefore expands the sample size by several thousand wells. However, the well controls are vitally important for comparing similar investment opportunities, so the magnitude of the coefficient on β_1 is inflated. Column (10) runs the regression in levels rather than logs. As demonstrated by the adjusted R^2, the level regression does not explain as much of the variation as the main log-log specification.

Across all regressions, β_1 is significant. Alternative explanations based on outliers, fixed effects, and geographic area are not supported. In addition, unique investment opportunities within the continental United States do not seem reasonable. A majority of counties and zip codes contain wells operated by both types of firms, so many investment opportunities are similar. For example, Figure 4 displays wells operated by borrowing-base and non-borrowing-base firms in North Dakota. The dark lines demarcate counties, and the grey lines signify zip code boundaries. Within North Dakota, nearly all the geographic areas have wells operated by both types of firms.

Because borrowing-base status and size are closely related, a potential concern is that the borrowing-base indicator in the regressions is nearly collinear with size. If this is true, then the true explanation for the apparent increase in cumulative production is the higher productivity of smaller firms. To alleviate such concerns, I examine different size measures. Table 10 modifies the size control variable in case size is non-linear in the primary log-log specification. Column (1) includes a quadratic term for size and does not include an indicator for the borrowing base while Column (2) repeats the same specification but includes a borrowing-base indicator. In Column (1), both size variables are statistically significant. In Column (2), the borrowing-base indicator and the size variables are significant, and the coefficients on the size variables have not drastically changed. Columns (3), (5), (7), and (9) break the size of the firms into median, tercile, quartile, and quantile indicators, respectively, and remove the borrowing-base indicator; the lowest group contains the smallest firms and is the omitted group. Columns (4), (6), (8), and (10) add the borrowing-base indicator into the corresponding regressions. In each specification, the borrowing-base indicator is statistically significant. Further, the coefficient on the borrowing-base indicator is between .06 and .09. Although the borrowing-base covenant is correlated with size, borrowing-base status and size are not interchangeable.

7 Conclusion

This study examines whether a common covenant in the oil and gas industry is associated with differential investment behavior and well-level outcomes. Because of the comprehensive information available for horizontal oil wells, the key feature of the identification strategy is matching on investments. The granular fixed effects structure allows comparison of similar wells operated by either borrowing-base or non-borrowing-base firms. The five-year cumulative production regressions include zip code, geological rock, and first production year-quarter fixed effects while controlling for financial and well characteristics.

Relative to non-borrowing-base firms, borrowing-base firms have higher five-year cumulative production and higher maximum rates. In addition, borrowing-base firms produce at a higher percentage of the maximum oil rate during the five years of production. These results are consistent with the borrowing-base covenant encouraging productivity improvements because high-quality wells contribute to continued or expanded access to credit. Further, borrowing-base firms replace their reserves organically at a faster rate.

Although the borrowing-base covenant is most prominent in the oil and gas industry, several other industries commonly use borrowing-base covenants on revolving credit facilities. Manufacturing, services, and trade-retail are typical examples, and the assets upon which the borrowing-base covenant relies are often accounts receivable and inventory (Flannery and Wang, 2011).

The current study has several limitations. One limitation of the current study is the time period during which the production is measured. From 2010 through 2013, the spot price of oil was roughly stable, and this time period covers an early stage in the shale oil boom. Rampini and Viswanathan (2010) suggest that, for firms with higher opportunity costs, increased debt capacity in the current period could limit investment in future periods, especially if future periods involve negative price shocks. Because the oil price suffered a large shock at the end of 2014, borrowing-base firm behavior might have changed. Subsequent research can examine whether the present study's inferences hold outside of a stable price environment. Second, the tests are only associative, so there are no causal inferences about the borrowing-base covenant.

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Tables

Table 1: Financial Summary Statistics

	Mean	St. Dev.	Pctl(25)	Median	Pctl(75)	N
Panel A: Non-Borrowing-Base Firms						
Size	21,039	19,898	6,298	11,849	28,194	268
Debt-to-EBITDA	1.49	0.80	0.93	1.31	1.92	268
EBITDA-to-Interest	29.97	29.97	12.20	17.70	31.60	268
CurrentRatio	2.19	0.87	1.61	2.02	2.56	268
CSTI	0.05	0.06	0.01	0.03	0.08	268
ROA	0.01	0.03	0.01	0.02	0.03	268
Growth	0.03	0.10	0.01	0.03	0.05	268
FullCost	0.34	0.47	0	0	1	268
CreditUtil	0.14	0.23	0	0.02	0.2	268
NonRevLeverage	0.21	0.11	0.15	0.20	0.26	268
Commitments	2,419	1,754	1,250	1,787	2,981	268
Revolving-to-Debt	0.08	0.13	0.00	0.00	0.15	268
Revolving-to-Secured	0.04	0.20	0	0	0	268
Panel B: Borrowing-Base Firms						
Size	3,139	5,391	696	1,671	3,576	663
Debt-to-EBITDA	4.49	10.62	1.6	2.8	4.3	663
EBITDA-to-Interest	17.78	33.83	3.66	7.32	14.40	663
CurrentRatio	3.15	4.80	1.74	2.55	3.50	663
CSTI	0.04	0.15	0.002	0.01	0.03	663
ROA	0.00	0.06	−0.01	0.01	0.02	663
Growth	0.08	0.23	0.01	0.05	0.10	663
FullCost	0.51	0.50	0	1	1	663
CreditUtil	0.36	0.31	0.1	0.3	0.6	663
NonRevLeverage	0.25	0.19	0.11	0.25	0.36	663
Commitments	787	825	240	551	999	663
Revolving-to-Debt	0.32	0.34	0.03	0.19	0.51	663
Revolving-to-Secured	0.64	0.44	0.00	0.99	1.00	663

Size is the net value of property, plant, and equipment in millions USD. *Debt-to-EBITDA* is the ratio of total debt to trailing twelve-month EBITDA. *EBITDA-to-Interest* is the ratio of trailing twelve-month EBITDA to interest expense. *CurrentRatio* is the ratio of current assets plus the undrawn portion of the revolving credit facility to current liabilities. *CSTI* is cash and short-term investments scaled by net property, plant, and equipment. *ROA* for quarter *t* is net income for quarter *t* divided by net property, plant, and equipment from quarter *t*-1. *Growth* is the quarterly percentage increase or decrease of *Size*. *FullCost* is an indicator for whether the firm uses full cost accounting. *CreditUtilization* is the ratio of the amount of drawn revolving credit to the capacity of the revolving credit facility. *NonRevLeverage* is non-revolving debt divided by assets. *Commitments* is the capacity of a firm's revolving credit facility in millions USD. *Revolving-to-Debt* is the ratio of the amount of drawn revolving credit to total debt. *Revolving-to-Secured* is the ratio of the amount of secured drawn revolving credit to total secured debt. The financial data level is firm-quarter.

Table 2: Correlation Maxtrix

	BB	Size	CreditUtil	NonRevLeverage	Debt-EBITDA	EBITDA-Interest	CurrentRatio	CSTI	ROA	Growth	FullCost	Commitments	Revolving-Debt	Revolving-Secured
BB	0	-0.67	0.34	0.11	0.42	-0.42	0.18	-0.23	-0.20	0.17	0.15	-0.58	0.35	0.57
Size	-0.57	0	-0.41	0.12	-0.31	0.36	-0.11	0.10	0.19	-0.15	-0.18	0.91	-0.45	-0.41
CreditUtil	0.32	-0.33	0	-0.20	0.35	-0.22	-0.33	-0.45	-0.14	0.01	0.09	-0.31	0.67	0.46
NonRevLeverage	0.10	-0.07	-0.19	0	0.51	-0.50	0.11	0	-0.21	-0.10	0.12	0.12	-0.32	0.01
Debt-EBITDA	0.15	-0.11	0.13	0.08	0	-0.82	0.06	-0.16	-0.42	-0.08	0.05	-0.22	0.20	0.38
EBITDA-Interest	-0.17	0.27	-0.11	-0.34	-0.15	0	-0.22	0.14	0.39	0.17	0.07	0.28	-0.15	-0.31
CurrentRatio	0.11	-0.12	-0.09	-0.03	0.02	-0.08	0	0.10	-0.01	-0.03	-0.15	0	-0.07	0.08
CSTI	-0.03	0.03	-0.21	-0.01	0.01	0.02	0.26	0	0.15	0.02	0.01	0.07	-0.41	-0.33
ROA	-0.10	0.11	-0.11	-0.19	-0.11	0.09	0.04	-0.04	0	0.24	0.04	0.18	-0.10	-0.18
Growth	0.12	-0.09	0.06	-0.09	0.24	0.01	0.02	0.07	0.17	0	0.10	-0.18	0.04	0.05
FullCost	0.15	-0.15	0.09	0.14	0.02	0.16	-0.09	0.04	-0.05	0.09	0	-0.18	0.05	0
Commitments	-0.53	0.82	-0.29	0.01	-0.10	0.11	-0.09	0	0.10	-0.11	-0.19	0	-0.32	-0.25
Revolving-Debt	0.34	-0.33	0.59	-0.47	0.08	0.02	0.09	-0.17	-0.03	0.08	0.03	-0.33	0	0.67
Revolving-Secured	0.57	-0.30	0.43	-0.03	0.13	-0.18	0.07	-0.20	-0.09	0.08	0.05	-0.22	0.59	0

This table shows the correlation among the financial variables. The lower triangular portion of the table contains the Pearson correlations, and the upper triangular portion of the table contains the Spearman correlations.

Table 3: Production Summary Statistics: Well Level

Panel A: Oil Well Characteristics						
	Mean	St. Dev.	Pctl(25)	Median	Pctl(75)	N
BBWells	0.47	0.50	0	0	1	16,697
FiveYearOil	119,162	100,298	43,733	96,372	167,838	16,697
MaxRate	393	349.47	166	316	534	16,697
MonthMaxRate	2.27	1.64	2	2	3	16,697
DeclineRate-5YearToMax	0.16	0.08	0.10	0.15	0.20	16,697
DeclineRate-FinalTwoYear	0.14	0.10	0.07	0.12	0.18	16,697
DrillMonthToProduction	3.81	2.62	2	3	5	16,697
LateralLength	6,165	2,145	4,574	5,273	7,358	16,697

Panel B: Differences in Residualized Well Characteristics			
	Non-BB Firms	BB Firms	t-statistic
FiveYearOil (barrels)	−1449	1658	−2.91
MaxRate (barrels per day)	−3.82	4.37	−1.90
MonthMaxRate (months)	0.01	−0.01	0.54
DrillMonthToProduction (months)	0.00	0.00	0.27
LateralLength (feet)	−0.87	0.99	−0.11

Panel A displays the distributions for the well-level characteristics. $BBWells$ is an indicator that equals one if the well is operated by a borrowing-base firm. $FiveYearOil$ is the cumulative amount of barrels of oil for the first five years of production. $MaxRate$ is the average number of barrels of oil per day for the month of highest oil production. $MonthMaxRate$ is the event-time month of $MaxRate$ relative to the month of first production. $DeclineRate$-$5YearToMax$ is the rate of oil production based on $FiveYearOil$ divided by $MaxRate$. $DeclineRate$-$FinalTwoYear$ is the rate of oil production from three years to five years divided by $MaxRate$. $DrillMonthToProduction$ is the number of months from the spud month to the first production month. $LateralLength$ is the length of the horizontal section of the well in feet. Panel B displays the differences in residualized well characteristics. The residuals are calculated by regressing each variable on the production year-quarter and zip code-rock fixed effects.

Table 4: Oil Cumulative Production: 2010Q2-2013Q4

	Dependent variable:		
	$LnFiveYearOil_{j,i,t}$		
	(1)	(2)	(3)
BB_i	0.182***	0.177***	0.094***
	(0.052)	(0.029)	(0.035)
$LnSize_{i,t-1}$	0.064***	0.062**	0.039***
	(0.022)	(0.026)	(0.011)
$CreditUtil_{i,t-1}$	−0.058	−0.088	−0.054
	(0.064)	(0.083)	(0.042)
$NonRevLeverage_{i,t-1}$	−0.085	−0.089	−0.003
	(0.152)	(0.099)	(0.104)
$Debt-EBITDA5_{i,t-1}$		−0.066	−0.015
		(0.057)	(0.047)
$EBITDA-Int2_{i,t-1}$		−0.004	0.039
		(0.043)	(0.064)
$CurrRatio1_{i,t-1}$		0.095**	0.041
		(0.040)	(0.028)
$CSTI_{i,t-1}$		0.195	0.062
		(0.208)	(0.113)
$ROA_{i,t-1}$		−0.474	−0.221
		(0.300)	(0.237)
$Growth_{i,t-1}$		0.067	−0.054
		(0.120)	(0.085)
$FullCost_i$		0.020	−0.008
		(0.072)	(0.033)
$LnLateralLength_{j,t}$			0.236***
			(0.036)
$LnMonthToProd_{j,t}$			−0.021
			(0.014)
$LnMaxRate_{j,t}$			0.837***
			(0.031)
$FirstMonthGOR_{j,t}$			−0.00000***
			(0.00000)
$FirstMonthWOR_{j,t}$			−0.00001***
			(0.00000)
Fixed Effects	ProdYrCQ	ProdYrCQ	ProdYrCQ
	Zip x Rock	Zip x Rock	Zip x Rock
Standard Errors	Firm	Firm	Firm
Observations	16,697	16,697	16,697
Adjusted R^2	0.692	0.692	0.881
Note:			*p<0.1; **p<0.05; ***p<0.01

The dependent variable in the regressions is the natural logarithm of five-year cumulative oil. BB is an indicator that equals one if the firm has a borrowing-base covenant. $LnSize$ is the natural logarithm of net property, plant, and equipment. $CreditUtil$ is the ratio of the amount of drawn revolving credit to commitments. $NonRevLeverage$ is non-revolving debt divided by total assets. *Debt-to-*$EBITDA5$ is an indicator that equals one if the Debt-to-EBITDA ratio is greater than five. $EBITDA$*-to-*$Int2$ is an indicator that equals one if the EBITDA-to-Interest Expense ratio is less than two. $CurrRatio1$ is an indicator that equals one if the current ratio is less than one. $CSTI$ is cash and short-term investments scaled by net property, plant, and equipment. ROA for quarter t is net income for quarter t divided by net property, plant, and equipment from quarter t-1. $Growth$ is the quarterly percentage increase or decrease in net property, plant, and equipment. $FullCost$ is an indicator for whether the firm uses full cost accounting. $LnLateralLength$ is the natural logarithm of the horizontal length of the well. $LnMonthToProd$ is the natural logarithm of one plus the number of months from drilling to production. $LnMaxRate$ is the peak rate of oil production in barrels of oil per day. $FirstMonthGOR$ is the ratio of natural gas to oil during the first month of production. $FirstMonthWOR$ is the ratio of water to oil during the first month of production. All regressions include fixed effects for the year-quarter of first production and for the interaction of zip code and geological rock. Standard errors are reported in parentheses and are clustered by firm.

Table 5: Oil Cumulative Production Intervals: 2010Q2-2013Q4

	Dependent variable:			
	$LnOneYear_{j,i,t}$	$LnTwoYear_{j,i,t}$	$LnThreeYear_{j,i,t}$	$LnFourYear_{j,i,t}$
	(1)	(2)	(3)	(4)
BB_i	0.094***	0.102***	0.099***	0.096***
	(0.032)	(0.034)	(0.034)	(0.035)
$LnSize_{i,t-1}$	0.025***	0.037***	0.039***	0.039***
	(0.009)	(0.011)	(0.011)	(0.011)
$CreditUtil_{i,t-1}$	−0.047	−0.038	−0.042	−0.051
	(0.039)	(0.040)	(0.042)	(0.042)
$NonRevLeverage_{i,t-1}$	−0.111	−0.031	−0.009	−0.006
	(0.099)	(0.102)	(0.103)	(0.103)
$Debt - EBITDA5_{i,t-1}$	−0.040	−0.036	−0.029	−0.022
	(0.041)	(0.043)	(0.045)	(0.046)
$EBITDA - Int2_{i,t-1}$	−0.095	−0.030	0.026	0.036
	(0.127)	(0.095)	(0.068)	(0.062)
$CurrRatio1_{i,t-1}$	0.023	0.037	0.038	0.042
	(0.029)	(0.031)	(0.029)	(0.029)
Other Financial Controls	Yes	Yes	Yes	Yes
Well Controls	Yes	Yes	Yes	Yes
Fixed Effects	ProdYrCQ	ProdYrCQ	ProdYrCQ	ProdYrCQ
	Zip x Rock	Zip x Rock	Zip x Rock	Zip x Rock
Standard Errors	Firm	Firm	Firm,	Firm
Observations	16,697	16,697	16,697	16,697
Adjusted R^2	0.889	0.885	0.885	0.884
Note:				*p<0.1; **p<0.05; ***p<0.01

The dependent variables in the regressions are the natural logarithms of production over different time intervals. BB is an indicator that equals one if the firm has a borrowing-base covenant. $LnSize$ is the natural logarithm of net property, plant, and equipment. $CreditUtil$ is the ratio of the amount of drawn revolving credit to commitments. $NonRevLeverage$ is non-revolving debt divided by total assets. *Debt-to-*$EBITDA5$ is an indicator that equals one if the Debt-to-EBITDA ratio is greater than five. $EBITDA$*-to-*$Int2$ is an indicator that equals one if the EBITDA-to-Interest Expense ratio is less than two. $CurrRatio1$ is an indicator that equals one if the current ratio is less than one. The other financial controls and well controls are described in Table 4. All regressions include fixed effects for the year-quarter of first production and for the interaction of zip code and geological rock. Standard errors are reported in parentheses and are clustered by firm.

Table 6: Maximum Oil Rate: 2010Q2-2013Q4

	Dependent variable:		
	$LnMaxRate_{j,i,t}$		
	(1)	(2)	(3)
BB_i	0.127*	0.115*	0.123*
	(0.066)	(0.063)	(0.066)
$LnSize_{i,t-1}$	0.034*	0.033*	0.040*
	(0.021)	(0.019)	(0.021)
$CreditUtil_{i,t-1}$	−0.027	−0.050	−0.047
	(0.061)	(0.056)	(0.071)
$NonRevLeverage_{i,t-1}$	−0.124	−0.124	−0.107
	(0.159)	(0.121)	(0.167)
$Debt-EBITDA5_{i,t-1}$		−0.056	−0.050
		(0.063)	(0.043)
$EBITDA-Int2_{i,t-1}$		−0.045	−0.049
		(0.064)	(0.068)
$CurrRatio1_{i,t-1}$		0.064*	0.054
		(0.037)	(0.041)
Other Financial Controls	Yes	Yes	Yes
Well Controls	Yes	Yes	Yes
Fixed Effects	ProdYrCQ	ProdYrCQ	ProdYrCQ
	Zip x Rock	Zip x Rock	Zip x Rock
Standard Errors	Firm	Firm	Firm
Observations	16,697	16,697	16,697
Adjusted R^2	0.631	0.632	0.642
Note:			*p<0.1; **p<0.05; ***p<0.01

The dependent variable in the regressions is the maximum one-month rate of oil production in barrels of oil per day. BB is an indicator that equals one if the firm has a borrowing-base covenant. $LnSize$ is the natural logarithm of net property, plant, and equipment. $CreditUtil$ is the ratio of the amount of drawn revolving credit to commitments. $NonRevLeverage$ is non-revolving debt divided by total assets. $Debt\text{-}to\text{-}EBITDA5$ is an indicator that equals one if the Debt-to-EBITDA ratio is greater than five. $EBITDA\text{-}to\text{-}Int2$ is an indicator that equals one if the EBITDA-to-Interest Expense ratio is less than two. $CurrRatio1$ is an indicator that equals one if the current ratio is less than one. The other financial controls and well controls are described in Table 4. All regressions include fixed effects for the year-quarter of first production and for the interaction of zip code and geological rock. Standard errors are reported in parentheses and are clustered by firm.

Table 7: Oil Decline Rates: 2010Q2-2013Q4

	Dependent variable:					
	$1YearDecline_{j,i,t}$	$2YearDecline_{j,i,t}$	$3YearDecline_{j,i,t}$	$5YearDecline_{j,i,t}$	$1to2YearDecline_{j,i,t}$	$3to5YearDecline_{j,i,t}$
	(1)	(2)	(3)	(4)	(5)	(6)
BB_i	0.023***	0.022***	0.018***	0.014***	0.020***	0.012*
	(0.009)	(0.008)	(0.006)	(0.005)	(0.007)	(0.006)
$LnSize_{i,t-1}$	0.008***	0.009***	0.007***	0.006***	0.010***	0.005***
	(0.003)	(0.002)	(0.002)	(0.002)	(0.003)	(0.002)
$CreditUtil_{i,t-1}$	−0.005	−0.001	−0.003	−0.003	0.002	−0.007
	(0.012)	(0.009)	(0.008)	(0.006)	(0.009)	(0.007)
$NonRevLeverage_{i,t-1}$	−0.012	0.014	0.015	0.013	0.040*	0.018
	(0.029)	(0.025)	(0.021)	(0.016)	(0.024)	(0.018)
$Debt-EBITDA5_{i,t-1}$	−0.012	−0.007	−0.004	−0.002	−0.002	0.003
	(0.013)	(0.010)	(0.008)	(0.006)	(0.008)	(0.007)
$EBITDA-Int2_{i,t-1}$	0.008	0.005	0.002	−0.001	0.002	−0.007
	(0.016)	(0.012)	(0.010)	(0.008)	(0.010)	(0.010)
$CurrRatio1_{i,t-1}$	0.002	0.006	0.005	0.004	0.010**	0.004
	(0.008)	(0.006)	(0.005)	(0.004)	(0.005)	(0.004)
Other Financial Controls	Yes	Yes	Yes	Yes	Yes	Yes
Well Controls	Yes	Yes	Yes	Yes	Yes	Yes
Fixed Effects	ProdYrCQ	ProdYrCQ	ProdYrCQ	ProdYrCQ	ProdYrCQ	ProdYrCQ
	Zip x Rock	Zip x Rock	Zip x Rock	Zip x Rock	Zip x Rock	Zip x Rock
Standard Errors	Firm	Firm	Firm	Firm	Firm	Firm
Observations	16,697	16,697	16,697	16,697	16,697	16,697
Adjusted R^2	0.377	0.387	0.397	0.412	0.350	0.400
Note:						*p<0.1; **p<0.05; ***p<0.01

The dependent variables in the regressions are the decline rates over different time intervals. The decline rate for a given interval is the production rate for that interval scaled by the maximum one-month production rate. BB is an indicator that equals one if the firm has a borrowing-base covenant. $LnSize$ is the natural logarithm of net property, plant, and equipment. $CreditUtil$ is the ratio of the amount of drawn revolving credit to commitments. $NonRevLeverage$ is non-revolving debt divided by total assets. *Debt-to-$EBITDA5$* is an indicator that equals one if the Debt-to-EBITDA ratio is greater than five. *$EBITDA$-to-$Int2$* is an indicator that equals one if the EBITDA-to-Interest Expense ratio is less than two. $CurrRatio1$ is an indicator that equals one if the current ratio is less than one. The other financial controls and well controls are described in Table 4. All regressions include fixed effects for the year-quarter of first production and for the interaction of zip code and geological rock. Standard errors are reported in parentheses and are clustered by firm.

Table 8: Reserve Replacement Ratios: 2010-2013

	Dependent variable:			
	$RRR_{i,t}$			
	Organic	Revisions	Purchase	All
	(1)	(2)	(3)	(4)
BB_i	2.315***	2.897***	1.736*	1.743*
	(0.772)	(1.012)	(0.895)	(0.895)
$LnDCF_{i,t-1}$	−0.0001*	−0.0001	−0.0002**	−0.0002**
	(0.00005)	(0.0001)	(0.0001)	(0.0001)
$CreditUtil_{i,t}$	−1.634	−1.124	−0.619	−0.613
	(1.318)	(1.353)	(1.777)	(1.777)
$Leverage_{i,t}$	−0.463	−0.838	−2.343	−2.275
	(3.713)	(3.711)	(4.023)	(4.029)
$Debt\text{-}to\text{-}EBITDAX5_{i,t}$	−3.994***	−3.787***	8.612*	8.570*
	(1.190)	(1.101)	(4.495)	(4.470)
$EBITDAX\text{-}to\text{-}Interest2_{i,t}$	−0.811	0.917	−3.231	−3.246
	(2.940)	(2.860)	(4.788)	(4.788)
$CurrRatio1_{i,t}$	6.097***	5.439***	5.445**	5.422**
	(1.750)	(1.876)	(2.710)	(2.718)
$CSTI_{i,t}$	10.114*	12.418**	2.151	1.840
	(5.543)	(6.125)	(5.865)	(5.904)
$ROA_{i,t}$	−5.214**	−1.231	3.633	3.608
	(2.041)	(2.672)	(3.275)	(3.280)
$FullCost_i$	−0.438	−0.830	−1.324	−1.329
	(1.147)	(1.019)	(1.244)	(1.244)
$AvgPrcOil_{i,t}$	−0.180***	−0.179***	−0.177	−0.180
	(0.068)	(0.064)	(0.109)	(0.109)
Fixed Effects	Year	Year	Year	Year
Observations	196	196	196	196
Adjusted R^2	0.103	0.113	0.121	0.120
Note:				*p<0.1; **p<0.05; ***p<0.01

The dependent variables in the regressions are reserve replacement ratios. Column (1) includes only reserve extensions and improved recovery. Column (2) includes reserve extensions, improved recovery, and revisions. Column (3) includes reserve extensions, improved recovery, revisions, and purchases. Column (4) contains all the methods from Column (3) plus other adjustments. All dependent variables are scaled by the total oil produced during the past year. BB is an indicator that equals one if the firm has a borrowing-base covenant. $LnDCF$ is the natural logarithm of standardized discounted cash flows. $AvgPrcOil$ is the firm's average, unhedged price of a barrel of oil. Other control variables are defined in Table 4. Standard errors are reported in parentheses and are clustered by firm.

Table 9: Robustness for Oil Cumulative Production: 2010Q2-2013Q4

	Dependent variable:									
	$LnFiveYearOil_{i,j,t}$									
	Max80	Lat80	Prod80	FE1	FE2	FE3	FE4	SE	No Well	Level
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
BB_i	0.073**	0.069*	0.069**	0.081*	0.092**	0.068**	0.070**	0.094**	0.304***	10,296.070***
	(0.031)	(0.035)	(0.031)	(0.046)	(0.037)	(0.033)	(0.032)	(0.043)	(0.077)	(2,668.691)
$LnSize_{i,t-1}$	0.035***	0.036***	0.034***	0.045***	0.046***	0.037***	0.023**	0.039***	0.088***	
	(0.012)	(0.012)	(0.012)	(0.012)	(0.012)	(0.012)	(0.011)	(0.014)	(0.027)	
$Size_{i,t-1}$										0.289*
										(0.148)
$CreditUtilization_{i,t-1}$	−0.031	−0.057	−0.030	−0.033	−0.047	−0.013	−0.065*	−0.054	−0.167	−17,660.300**
	(0.039)	(0.050)	(0.041)	(0.044)	(0.048)	(0.049)	(0.040)	(0.070)	(0.103)	(7,105.475)
$NonRevLeverage_{i,t-1}$	0.025	−0.019	−0.018	−0.008	0.024	0.072	−0.046	−0.003	−0.083	7,131.643
	(0.098)	(0.108)	(0.094)	(0.109)	(0.112)	(0.116)	(0.093)	(0.079)	(0.205)	(9,259.350)
$Debt\text{-}EBITDA5_{i,t-1}$	0.002	0.009	0.020	0.009	−0.045	−0.052	−0.014	−0.015	−0.069	−1,735.774
	(0.043)	(0.050)	(0.036)	(0.047)	(0.046)	(0.050)	(0.041)	(0.036)	(0.074)	(4,594.226)
$EBITDA\text{-}Int2_{i,t-1}$	0.046	0.016	0.052	0.045	0.105*	0.057	0.040	0.039	0.322	3,204.614
	(0.049)	(0.058)	(0.057)	(0.067)	(0.063)	(0.080)	(0.060)	(0.073)	(0.306)	(7,363.034)
$CurrRatio1_{i,t-1}$	0.042	0.044	0.054*	0.031	0.034	0.047	0.042	0.041	0.038	6,194.970***
	(0.034)	(0.028)	(0.032)	(0.030)	(0.030)	(0.032)	(0.027)	(0.026)	(0.067)	(1,887.858)
$LnLateralLength_{j,t}$	0.296***	0.374***	0.257***	0.223***	0.225***	0.268***	0.196***	0.236***		
	(0.025)	(0.026)	(0.040)	(0.030)	(0.034)	(0.033)	(0.032)	(0.063)		
$LnMonthToProd_{j,t}$	−0.018	−0.017	−0.028*	−0.007	−0.019	−0.009	0.003	−0.021		
	(0.015)	(0.016)	(0.015)	(0.017)	(0.012)	(0.015)	(0.013)	(0.016)		
$LnMaxRate_{j,t}$	0.788***	0.828***	0.625***	0.849***	0.847***	0.808***	0.861***	0.837***		
	(0.021)	(0.032)	(0.027)	(0.028)	(0.036)	(0.033)	(0.027)	(0.039)		
$LateralLength_{j,t}$										9.379***
										(1.853)
$MonthToProd_{j,t}$										−465.210*
										(282.617)
$MaxRate_{j,t}$										124.235***
										(18.137)
Other Financial Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Other Well Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
Fixed Effects	Main	Main	Main	ProdYrCQ County x Rock	ProdYrCQ Zip x Rock (TX) Township x Rock (NonTX)	ProdYrCQ x Zip x Rock	ProdYrCQ x MaxMonth Zip x Rock	Main	Main	Main
Standard Errors	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm, Rock	Firm	Firm
Observations	13,358	13,359	13,357	16,697	16,697	16,697	16,697	16,697	21,517	16,697
Adjusted R^2	0.787	0.878	0.775	0.873	0.883	0.900	0.889	0.881	0.602	0.670

Note: *p<0.1; **p<0.05; ***p<0.01

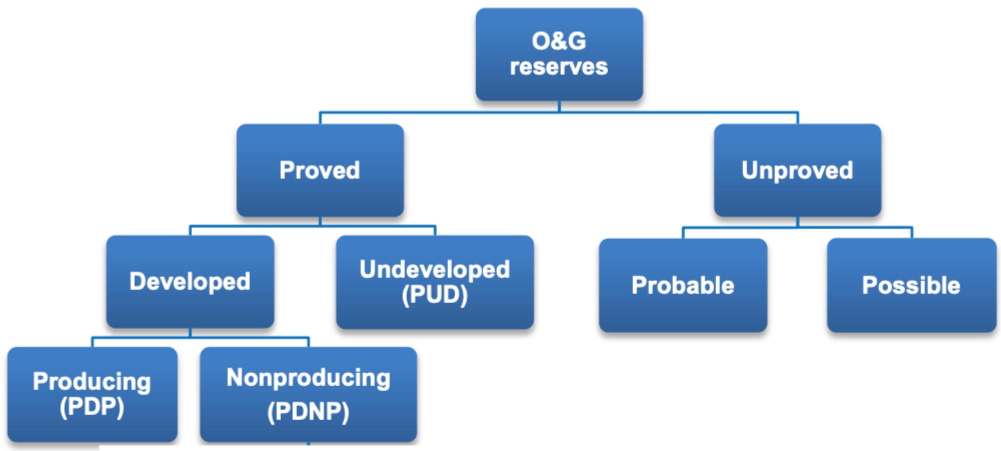
The dependent variable in the regressions is the natural logarithm of final cumulative five-year oil production. BB is an indicator that equals one if the firm has a borrowing-base covenant. Financial and well controls are defined in Table 4. Main fixed effects include production year-quarter and zip code-rock fixed effects. Standard errors are reported in parentheses and are clustered by either firm or firm and geological rock.

Table 10: Size Robustness for Oil Cumulative Production: 2010Q2-2013Q4

	Dependent variable:									
	$LnFiveYearOil_{j,i,t}$									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
BB_i		0.089**		0.066**		0.065*		0.082**		0.093***
		(0.035)		(0.032)		(0.037)		(0.032)		(0.031)
$LnSize_{i,t-1}$	−0.293***	−0.262***								
	(0.095)	(0.097)								
$(LnSize)^2_{i,t-1}$	0.018***	0.017***								
	(0.005)	(0.005)								
$Median_{i,t}$			0.040	0.068**						
			(0.036)	(0.033)						
$Tercile2_{i,t}$					−0.019	−0.014				
					(0.036)	(0.037)				
$Tercile3_{i,t}$					0.0002	0.034				
					(0.038)	(0.042)				
$Quartile2_{i,t}$							−0.026	−0.021		
							(0.042)	(0.045)		
$Quartile3_{i,t}$							0.017	0.035		
							(0.038)	(0.040)		
$Quartile4_{i,t}$							0.025	0.074		
							(0.046)	(0.046)		
$Quintile2_{i,t}$									−0.044	−0.042
									(0.049)	(0.053)
$Quintile3_{i,t}$									−0.054	−0.044
									(0.053)	(0.057)
$Quintile4_{i,t}$									−0.051	−0.022
									(0.041)	(0.046)
$Quintile5_{i,t}$									−0.001	0.061
									(0.048)	(0.047)
Financial Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Well Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Fixed Effects	Main	Main	Main	Main	Main	Main	Main	Main	Main	Main
Standard Errors	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm
Observations	16,697	16,697	16,697	16,697	16,697	16,697	16,697	16,697	16,697	16,697
Adjusted R^2	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.881	0.881
Note:						*p<0.1; **p<0.05; ***p<0.01				

The dependent variable in the regressions is the natural logarithm of cumulative five-year oil production. These regressions include different controls for size. BB is an indicator that equals one if the firm has a borrowing-base covenant. $LnSize$ is the natural logarithm of net property, plant, and equipment. $Median$, $Tercile$, $Quartile$, and $Quintile$ are indicators for the group in which the firm falls. The omitted group is the smallest group. Financial and well controls are defined in Table 4. Main fixed effects include production year-quarter and zip code-rock fixed effects. Standard errors are reported in parentheses and are clustered by firm.

Figures



Source: OCC

Figure 1: Reserve Categories: OCC Comptroller's Handbook

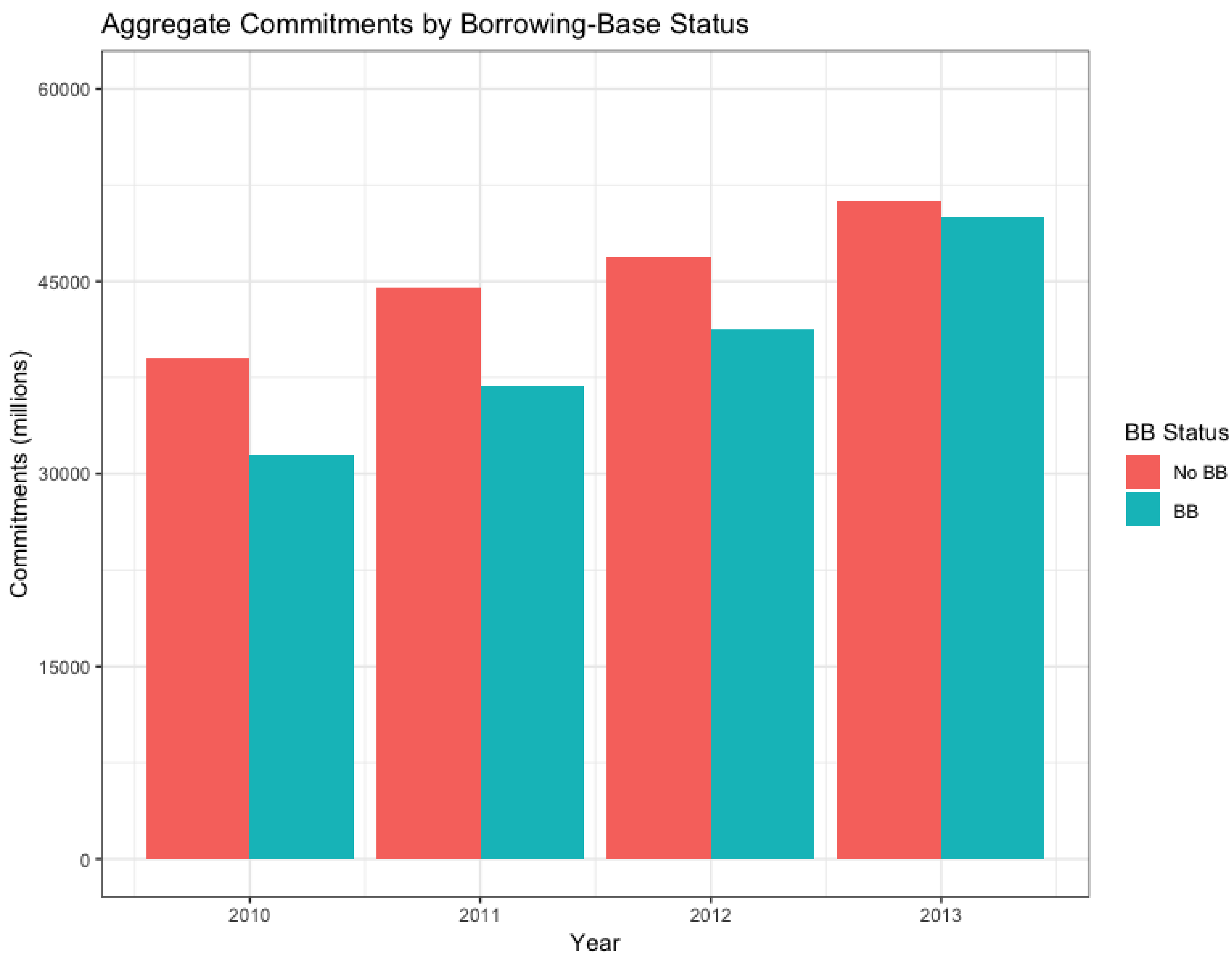


Figure 2: Aggregate commitments for firms with and without borrowing-base covenants by year

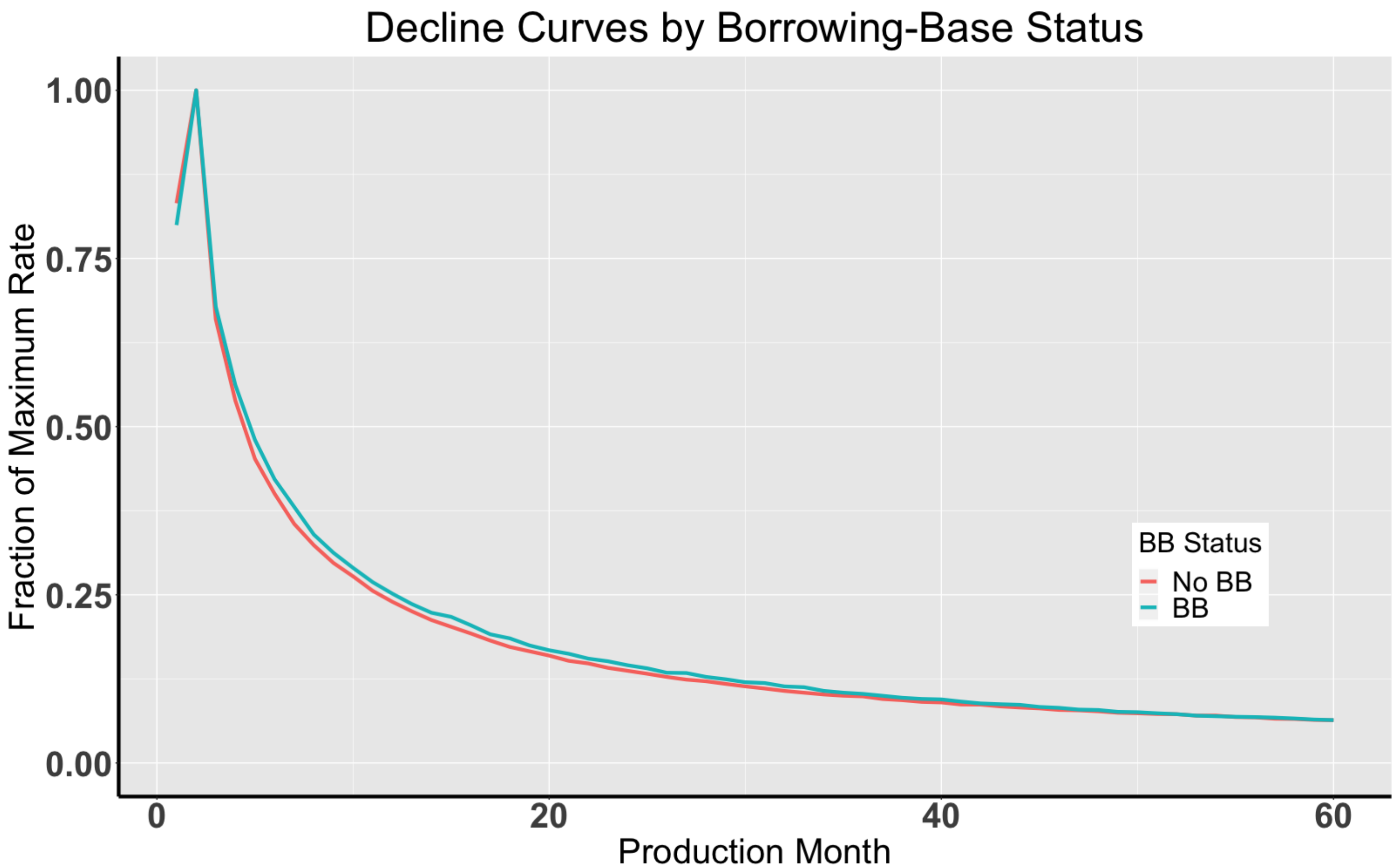


Figure 3: Average normalized decline curves for wells with maximum oil rate in second month for borrowing-base and non-borrowing-base wells.

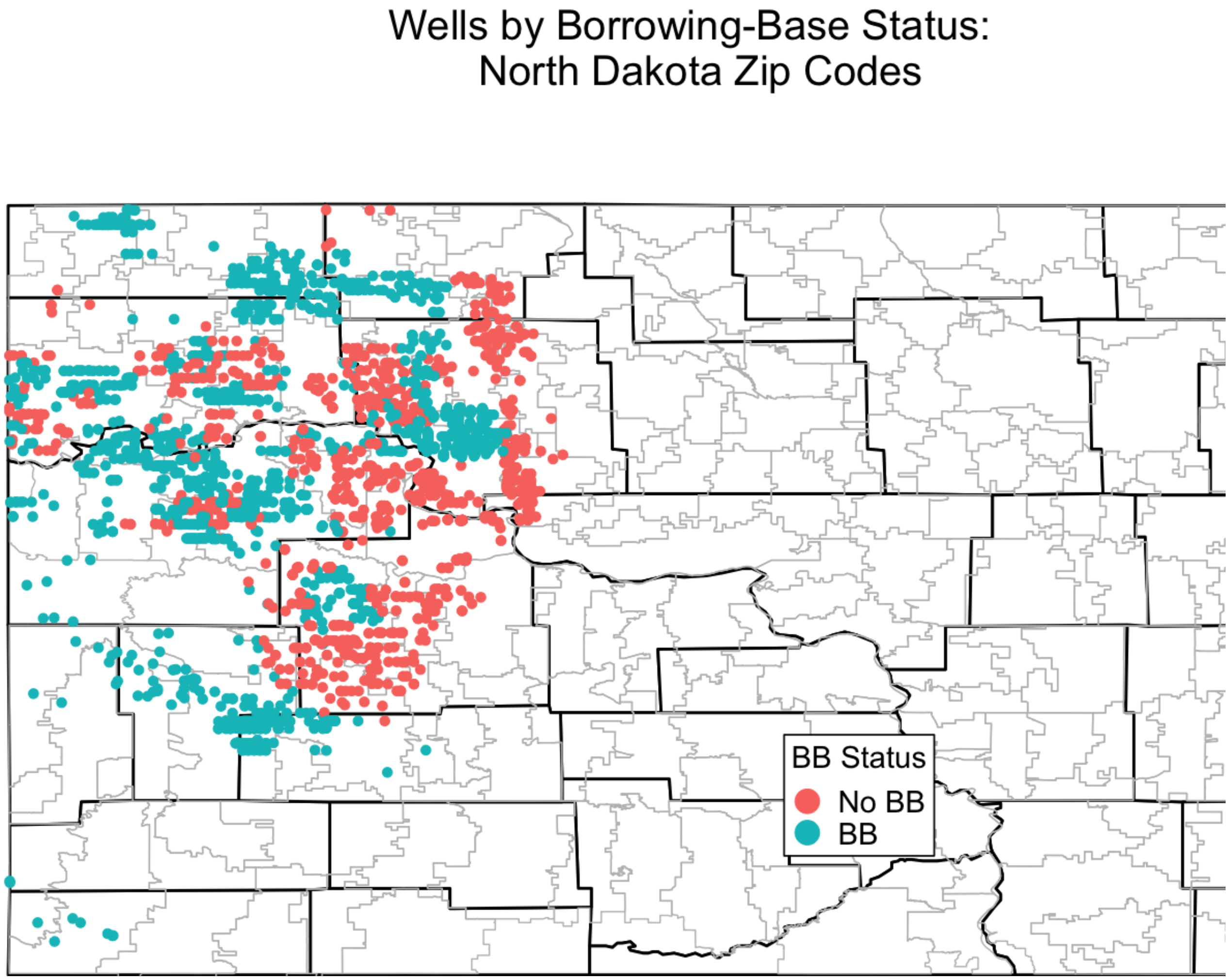


Figure 4: Wells operated by borrowing-base and non-borrowing-base firms in North Dakota drilling into the Bakken formation. The black lines display county boundaries, and the gray lines demarcate zip codes.