# Forced Cooperation vs. Competitive Holdouts: Efficient land use policies in the oil and natural gas industry[1]

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**Abstract**

Eminent domain policies are widely applied in many different settings, yet there is little empirical evidence measuring the effects of these policies on economic outcomes. The welfare effects of these policies are ambiguous whereby the ability to bypass costly holdout property rights owners may be beneficial, the revocation of exclusion rights generally leads to lower prices for owners. In this paper, I use variation in state-level policies to quantify some of the costs and benefits of eminent domain policies in the context of oil and natural gas extraction. These policies are designed to balance the tension between preserving private property ownership and allowing publicly beneficial projects to proceed. I find that production efficiency gains are greatest when targeted to the scale of economic use, a gain of approximately $2,591 per acre, and marginal production losses from policies that do not strictly regulate firms' drilling behavior. Further, I find evidence of contracting losses for private property owners that negotiate late, resulting in a 30% decrease in contract concessions benefiting them. Finally, the study documents the industry changes in contracting costs more broadly.

**Keywords:** Oil & Natural Gas Leasing; Private Contracting; Anticommons.

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# 1 Introduction

Many industries are characterized by projects that require the cooperation of many property rights owners. For example, cooperation determines whether private builders can commence construction projects, the profitability of wireless firms assembling spectrum licenses, whether oil and natural gas drillers can bore a hole into the ground, and natural resource management, more generally, among other examples. Individual sellers of the fragmented property rights have an incentive to get the best price for their good and "hold out," or refuse to cooperate, until they do. Among private buyers, particularly high prices to coordinate a few holdouts may thwart the proposed projects altogether, or these projects may be redesigned to work around the holdouts.[1] Governments use coercive, eminent domain techniques to assemble the desired property before a public project begins. A lesser known regulation is eminent domain for private projects. In addition to moving projects forward, eminent domain policies allow property rights owners to profit from their ownership share by selling to prospective buyers or by coordinating with other small property rights owners when the individual ownership shares are too small to be valuable alone. Conversely, property rights owners may highly value not letting the project proceed, and these policies strip them of their exclusion rights given enough of their neighbors disagree with their distaste. Finally, while these policies decrease contracting costs for prospective buyers, lowering these costs may over-incentivize project investments. The oil and natural gas industry employs eminent domain for private drilling projects, and this paper studies how these regulatory methods affect private contracting outcomes and natural resource production.

The oil and natural gas industry is a particularly interesting setting to study the effect of eminent domain policies because there is a complicated mix of private and public incentives driving actors to pursue a drilling project or not, and the prevalence of these risks has evolved with the technological changes in the industry. Within the oil and natural gas industry, the costs of contracting changed significantly in the last twenty years due to significant technological changes. I begin by exploring how introducing large-scale, shale extraction technology changed the industry in terms of increasing the contracting costs to assemble land before drilling.[2,3] In light of these changes, regulators responded by granting more leniency to firms proposing drilling projects plagued with landowner holdouts, effectively granting eminent domain to private firms once there is enough voluntary cooperation among affected landowners.[4] Such eminent domain policy responses lower contracting costs by reducing the number of cooperating landowners required to drill a well. By

[1] Single, private buyers may also disguise as many buyers or employ secret buyers to hide the scope of the project. Kelly (2006) describes arguments regarding the "Public Use Clause" in a way that benefits a private party by arguing the eventual use as a public one. The conclusion is that private parties effectively assemble rights for private use using secret buyers, and employing eminent domain in these settings creates potential for *inordinate influence*.

[2] The trend analysis borrows from the method used by Finkelstein (2007) to measure the effect of Medicare introduction, which impacted the market all at once.

[3] Wang and Krupnick (2013) document the evolution of the shale revolution through a historical lens with an emphasis on the value of government investments.

[4] The specific policies existed well before the early 2000's; however, I will demonstrate that the frequency of eminent domain picked up at about the same time that firms adopted the technology.

reducing these costs, firms may find it desirable to drill more wells and compete for oil and gas production, and the literature has identified a series of short and long-term risks and lost property values associated with proximity to drilling[5] that are coupled with identified benefits.[6,7] Without these policies, fewer, viable wells may be drilled because the fragmented property rights are too expensive for private firms to assemble.[8] Through the empirical and theoretical analyses, I document that policies targeting coordination among mineral rights owners and drilling firms result in more overall production than policies targeting the mineral rights owners alone. However, the marginal production from each well drilled via eminent domain policy is less than production from non-eminent domain wells. Further, I present suggestive evidence that landowners subject to these policies lose contract value.

In this paper, I quantify the gains and losses in oil and natural gas production under variants of eminent domain policies that are designed to encourage more efficient production. First, I study a policy in Texas that lowers the contracting costs. I then compare well production in Texas to states that both lower contracting costs and require firms to coordinate drilling, and my estimates confirm existing empirical literature estimating the value of coordinated drilling and finds coordination increases average production outcomes. My estimates bound the effects of these eminent domain policies on production outcomes, revealing that production is more efficient when policy corrections are at the level of economic use. Further, I present evidence of a contracting cost borne by landowners that attempt to hold out for too long using data that describes the quantity of legal and environmental protections included in a subset of negotiated contracts.

To estimate the effect of policies that lower contracting costs alone, I focus the study on the

[5]There is a growing literature capturing the hedonic value of proximity to drilling activity in the environmental economics literature. Existing literature finds that households internalize perceived risks of nearby drilling activity through decreased property values (Muehlenbachs, Spiller, and Timmins (2015), Gopalakrishnan and Klaiber (2014), James and James (2014), Boxall, Chan, and McMillan (2005)), and a growing health literature finds that proximity to drilling is correlated with incidence of infant birth weight (Hill (2013)) and harm to drinking water (Hill and Ma (2017), Vengosh, Jackson, Warner, Darrah, and Kondash (2014)). Other identified concerns include increased truck traffic (Graham, Irving, Tang, Sellers, Crisp, Horwitz, Muehlenbachs, Krupnick, and Carey (2015)), air pollution, methane leaks (Brandt, Heath, Kort, O'sullivan, Pétron, Jordaan, Tans, Wilcox, Gopstein, Arent, et al. (2014)), and incidence of tremors (Koster and van Ommeren (2015) and Cheung, Wetherell, and Whitaker (2016)).

[6]Studies are also finding that cleaner air due to substituting coal fire power plants with natural gas, as in Johnsen, LaRiviere, and Wolff (2017), are having positive effect, and Cesur, Tekin, and Ulker (2017) measured changes to air quality impacts on infant mortality. Other studies cite economic benefits of "fracking" like Mason, Muehlenbachs, and Olmstead (2015) and Bartik, Currie, Greenstone, and Knittel (2016). Jackson, Vengosh, Carey, Davies, Darrah, O'sullivan, and Pétron (2014) review costs and benefits of fracturing more broadly.

[7]The U.S. Energy Information Administration reports that the Americas are the second largest region in natural gas reserves and resources, with roughly 3,000 trillion cubic feet of estimated shale recovery.
*Source:* `https://www.eia.gov/conference/2014/pdf/presentations/yo.pdf`
Beyond the quantity of resources, the availability of natural gas has impacted other industries like chemical and other manufacturing processes that rely on natural gas.
*Source:* `https://www.washingtonpost.com/business/economy/the-new-boom-shale-gas-fueling-an-american\-industrial-revival/2012/11/14/73e5bb8e-fcf9-11e1-b153-218509a954e1_story.html?utm_term=.eddd87ed2ce8`

[8]Leonard and Parker (2016) find that greater fragmentation leads to fewer total wells drilled using a natural experiment that varies mineral ownership based on Native American land tenure dating to the 1800's. They are able to empirically show under-use as a result of too much property rights fragmentation. Regulation that lowers contracting costs, as expected, should lead to more wells, which I address by evaluating an empirical relationship between well density and levels of eminent domain.

state of Texas and the regulatory exceptions that allow firms to drill wells nearer to existing wells and unleased minerals. If granted an exception, the proposed drilling units are allowed to be more irregularly shaped and densely spaced (within the context of all wells drilled in Texas). Comparing production outcomes across wells drilled with and without exceptions, I am able to quantify the costs and benefits of regulations designed primarily to decrease contracting costs by reducing the required number of landowner negotiations. I find that aggregate production is greater, but the marginal, exception well produces less. Empirically, a primary concern is that more wells with exceptions are drilled in areas with greater expected production, which would bias the ordinary least square (OLS) estimates upward. An opposing concern is that firms apply for "cost lowering" exceptions in areas where expected production is lower, thus downward biasing the OLS estimates. I provide empirical evidence that suggests firms are more likely concentrating their drilling efforts in highly productive areas, regardless of contracting costs, and productive areas happen to be located in regions with greater population density, and thus, higher contracting costs. To correct remaining positive bias, I estimate a well-level, instrumental variable model of production that takes the number of wells drilled as given and find a negative effect of exceptions wells on cumulative production. The instruments describe either different forms of contract costs, like a greater number of households or more lessor absenteeism,[9] or measures that characterize households who are more or less likely to contest a regulatory exception,[10] like households with higher median income or more education. Using the proposed identification strategies, I find that exceptions result in a total profit gain from more well production, but a marginal loss from each additional exception well. "Back of the envelope" calculations suggest a net 3% profit increase in oil and 23% profit increase for natural gas, which amounts to about a $15 and $34 per acre, respectively. However, these gains are dissipated completely if there are more exception wells drilled in the square mile region, leading to overall negative effects of the policy in Texas.

I then use a border discontinuity to estimate the benefits of policies that stipulate cooperation among landowners and drillers. States like New Mexico, Louisiana, and Oklahoma force-pool hold-out landowners, requiring them to participate in the proposed drilling unit, and these landowners are compensated with royalties paid based on their mineral ownership share.[11] On top of force-pooling, these states force-unitize, which requires firms to coordinate where and how they drill a well contained in a state-defined drilling unit.[12] Compulsory unitization is a mechanism used to address the tendency to over-drill the commons when too many firms own the rights to extract from a common reservoir. I compare production in Texas to that in New Mexico, and estimate a

[9]The state of Texas allows mineral rights to be severed from surface rights indefinitely, which increases the difficulty of finding the correct negotiating partner.

[10]When an exception is file with the state regulator, firms are required to notify the affected landowners. Landowners then have 30 days to contest the request, after which the regulator holds a hearing and the firm must demonstrate necessity for the exception.

[11]Eubanks and Mueller (1986) use the Oklahoma forced pooling laws to qualitatively discuss potential mechanisms driving increased incidence of drilling wells that are force pooled.

[12]Existing literature, like Libecap and Wiggins (1984) and Libecap and Wiggins (1985), studies the contracting between firms when there is compulsory unitization and where the state owns the rights to private minerals. Christopher and Kaffine (2011) applies lessons from oil field unitization to resource extraction more generally.

difference in well production when a well is drilled in a state that uses regulations to coordinate private landowners and drilling activity. "Back of the envelope" calculations suggest that oil recovery is doubled in New Mexico compared to Texas, and the gains for gas are roughly 71% greater, which is a gain of $2,591 per acre at a low natural gas price.[13] Comparing the within Texas margin effect of regulation to that of the cross border margins, I conclude that states with unitization policies are more productive, which adds to the existing literature touting unitization in this industry.

As a final exercise, I analyze the implications of eminent domain for contracting concessions. Before drilling a well, a firm must have negotiated leases with all affected landowners. Under both eminent domain types, landowner holdouts, or landowners that refuse to sign a lease with a drilling firm, are unable to exercise the rights to their minerals if a majority of their neighbors have already agreed to lease. As firms amass the rights to neighboring minerals, the likelihood they are allowed to drill by these policies increases, and as a consequence, holdout landowners may lose their bargaining power if they hold out too long. I present empirical evidence that these contracts have, on average, around 30% fewer landowner concessions, increasing costs to landowners by exposing them to greater drilling risks.

This paper sets up a framework for evaluating partial equilibrium effects of these policies on unit-level production and is a starting point for future work that addresses holdout incentives for landowners negotiating private contracts. These estimates do not endeavor to present a complete picture of the industry impacts from technology adoption, expanded drilling, and regulatory constraints. I am able to quantify the costs to consumers through decreased royalty income and fewer landowner concessions in their private contracts. It does not address the loss in property value and increased risk exposure documented in the property value hedonic literature. My estimates, however, suggest that eminent domain policy is correlated with more well-dense regions, which is negatively valued in the hedonic literature and of concern to regulators limiting the "over-drilling" of natural resources.

This paper contributes to the "anticommons" literature that studies the underuse of economic goods under highly fragmented property rights, an issue studied in Buchanan and Yoon (2000)[14] in response to a law review article asserting there did not exist a formal model of the anticommons by Heller (1998).[15] Leonard and Parker (2016) apply the model in Buchanan and Yoon (2000) to study drilling behavior in North Dakota.[16] This paper expands their models to include regulatory effects from lower contracting costs, and uses the predictions of the model to understand the estimated results. The border discontinuity results add to similar findings along the Oklahoma and Texas border estimated by Balthrop and Schnier (2012). Their findings argue in favor of untiziation, or

[13] Balthrop and Schnier (2012) estimate an average gain of 3,360 barrels of oil in Oklahoma compared to Texas, which is comparable to the 4,550 barrels estimated along the Texas and New Mexico border using well level data.

[14] Interestingly, they identify the symmetry between the commons and anticommons problems in which a solution to both is property rights defined at the scale of economic use.

[15] He explores the situation of underuse among Moscow storefronts after the transition from socialism to a markets-based economy that argues property rights were not allocated to their most productive use.

[16] Using a natural experiment in which land tenure was historically decided for agricultural use, they find that greater private ownership (and fragmentation) results in fewer drilled wells and, thus, lower overall production.

coordination among firms drilling from a common reservoir, which is an oft studied problem with respect to oil and natural gas extraction like in Libecap and Wiggins (1984), Libecap and Wiggins (1985), and Christopher and Kaffine (2011), among others.

More generally, both holdup and eminent domain responses are commonly studied in the legal and economic theory literatures,[17] and these questions are also studied in land assembly problems of interest among urban economists.[18] This paper marks the beginning of a new empirical setting in which to explore these public and private incentives to holdout and the potential costs from thwarting exercise of these rights.

Finally, there is a significant legal literature concerned with issues of oil and natural gas regulation specific to the well density and spacing exceptions in Texas and forced pooling and unitization policies adopted more broadly. Especially since the change in technology, there is broad interest in exploring whether policies in place to manage the "Rule of Capture" governing oil and natural gas extraction and to protect private, correlative rights are still relevant tools in today's context. While estimates presented are based on partial equilibrium outcomes, they suggest that certain policies lead to more, average production, and that eminent domain comes with a contracting cost to landowners.

The remainder of the paper proceeds as follows. Section 2 begins with a discussion of the policies governing oil and natural gas drilling and a few details describing the technological changes that led to the "shale boom." Following the institutional details is Section 3 that describes the data used to construct the empirical analyses. Section 4 presents a conceptual framework of leasing and drilling behavior when there is property rights fragmentation, adding regulatory outcomes to the model in Leonard and Parker (2016). Section 5 marks the beginning of the empirical analyses that relate contracting costs to production outcomes, demonstrating a significant effect of technological changes in the industry, with effects more dramatically felt in densely populated regions. Section 7 quantifies the costs to the negotiated contract terms when firms and landowners reach agreement near the time when a firm applies for a well density or spacing exception in Texas. Finally, Section 8 summarizes the costs and benefits from the analyses and Section 9 concludes.

## 2 Regulatory Background & Institutional Details

In the United States, a large fraction of mineral rights are privately owned. Before wells are permitted by state regulators and drilled by firms, firms must amass the mineral rights to all subsurface acreage from which they want to extract by signing leases with private landowners. States may specify a "minimum spacing unit" that requires the leased acreage to be of a certain size or minimum distances to existing wells or unleased acreage, as described in Table 1. These poli-

[17] Kominers and Weyl (2012) present holdout as a prevention to aggregate decentralized, complementary goods. Che and Sákovics (2004) study a dynamic theory of holdout, and Felli and Roberts (2002) explore the effect of competition on holdout.

[18] Brooks and Lutz (2016) study the Los Angeles "to-be-assembled" land market and find a price premium that they attribute to frictions like holdout. Miceli and Segerson (2007) theoretically study land assembly with holdout under sequential bargaining.

cies aid regulators tasked with natural resource conservation and protection of private, correlative rights, even among small mineral rights owners. In addition to well spacing, density, and minimum acreage, states execute eminent domain policies that prevent landowners from holding up proposed drilling projects that fall under two broad categories: forced pooling and well density and spacing exceptions. The following section describes the policies relevant to the empirical analyses, and the Appendix provides additional regulatory and drilling/shale details.

In the context of oil and natural gas extraction, pooling refers to the process of assembling smaller mineral rights into a large enough spacing unit that is eligible for drilling. Highly fragmented property rights increase the need to assemble a larger number of individual rights, thereby increasing coordination costs. Compulsory pooling policies force holdout landowners to participate in the proposed drilling unit. Force-pooled landowners do not have exclusion rights to their property; however, they are compensated depending on the states' "Risk Penalty" policy and the type of ownership stake the landowner accepts. Force pooling is commonly used in New Mexico and Louisiana.[19] Firms drilling in Texas, on the other hand, may circumvent landowner holdouts by petitioning the state for well density and spacing exceptions, which allow them to drill wells nearer to existing well infrastructure, unleased property, or with substandard acreage. To be granted an exception, firms must notify the affected landowners and allow them thirty days to respond and trigger a hearing in Austin, Texas.[20] At a hearing, firms must demonstrate the necessity of the exception, and if granted, landowners that never sign a lease do not require compensation even if the drilled lateral can feasibly take oil or natural gas from their property. Both force-pooled and "excepted" landowners are exempt from laterals drilled through their minerals, but both coarse landowners into drilling units given there is enough voluntary cooperation among landowners' neighbors and allow firms the right to extract oil and natural gas from their mineral estates.[21]

Once the mineral rights are in place, firms apply for permits to drill wells, and states diverge, once more, wherein states like Louisiana and New Mexico enforce coordinated drilling and Texas, largely, does not. Unitization, or coordinated drilling, describes the joint development of a common reservoir across different firms owning mineral interest stakes. Unitization agreements are designed to minimize the number of wells drilled to efficiently extract oil and natural gas. In addition to estimating an effect of eminent domain policies on well production, I estimate an effect of the combined eminent domain and unitization policies using a cross border analysis.

## 2.1 Hydraulic fracturing

It is reported that the supply of shale gas to total US natural gas production jumped from 1.6 percent in 2000 to 23.1 percent by 2010 with increasing projections (Richardson, Gottlieb,

[19] Oklahoma force pools and unitizes well production, as well, however, that state is not studied in this analysis.

[20] A majority of exceptions are granted, even among those that convert after a hearing in Austin.

[21] Just how much voluntary cooperation is required depends on the states. New Mexico requires a 75% minimum acreage control, described in Table 1, which stipulates that 75% of the mineral acreage share must agree. Louisiana and Texas both do not state minimum acreage controls. In Louisiana, as long as the landowner with rights to the area where the well is drilled agrees, the remaining landowners in state-defined unit are pooled.

Table 1: Well Spacing and Density Rules by State

| | Texas | | Louisiana | | New Mexico | |
|---|---|---|---|---|---|---|
| | Gas | Oil | Gas | Oil | Gas | Oil |
| Min. Dist. from Property Line | 467 ft. | 467 ft. | 330 ft. | 330 ft. | 660 ft. | 330 ft. |
| Min. Dist. Existing Well | 1200 ft. | 1200 ft. | 2000 ft.[c] | 900 ft.[c] | | |
| Min. Spacing Unit | 40 acres | 40 acres | none | | 160 acres | 40 acres |
| Risk Penalty | < 100% | | 100% | | 200% | |
| Min. Acreage Control | none | | none | | 75% | |
| Severance Tax | 7.5% | 4.6% | 0.18/MCF[a] | 12.5% | 7.5%[b] | 7.8% |

[a] The average per MCF unit tax in Louisiana from 2007 to 2018, which is perhaps around 4%.
[b] There is an ad valorem property tax, as well, specific to the production district ranging from 1 to 1.5%.
[c] If wells are deeper than 3000 feet.
Notes: (i) Describes the well spacing and density rules across states in the study; (ii) *Min. Spacing Unit* refers to minimum size of acreage required to drill a well; (iii) *Risk Penalty* describes the additional costs owed by holdout landowners who are eventually compulsory pooled; (iv) *Min. Acreage Control* refers to the amount of acreage a firm must lease before attempting to force pool or unitize holdout landowners; (v) New Mexico's minimum spacing unit varies across counties and depends on well depth (320 acres for deep gas), but 160/40 are the default values for gas/oil wells; (vi) New Mexico's Min. Acreage control stipulates that the 75% must comprise of more than one landowner.

Krupnick, and Wiseman (2013)). Technological innovation in the oil and natural gas industry has increased access to reserves trapped in tight-shale formations like the Barnett and Haynesville Shale regions. Additionally, firms are able to extract from different shale strata by drilling new laterals in older plays, like those in the Permian Basin. The combination of large-scale hydraulic fracturing,[22] horizontal drilling techniques, and more precise 3-D seismic surveying techniques have unleashed access to otherwise unattainable resources with increased efficiency. Hydraulic fracturing involves injecting fluids[23] at high pressures into the drilled well such that the rock cracks and produces artificial fissures throughout the strata. The fracturing fluid contains proppants, like quartz sand grains, that keep the fissures open well after the fracturing fluid has returned to the wellhead once the pressure is released. Horizontal drilling techniques with laterals measuring roughly 3000 to 5000 feet ensure that large quantities of shale are exposed to the artificial stimulation generated by hydraulic fracturing while boring fewer holes to drill wells (Zeik (2009); King (2011)). Further, the fracturing stages can take place iteratively over the life of the well or all at once, allowing the firm more freedom to pace natural gas extraction with other operation decisions or market conditions.

## 2.2 Lease Agreements

In the empirical analyses, I use the individually negotiated contract terms to understand whether landowners may be loosing their bargaining power when firms exercise eminent domain policies. The negotiated leases can serve landowners as supplementary regulatory mechanisms, protecting their property and aesthetics, and mitigating their exposure to negative externalities during the

[22] Hydraulic fracturing has been in active use since the 1950s, and before the formal process developed, oil well operators used other artificial forms of stimulation to extract oil and gas (Zeik (2009)).
[23] Potential fracturing fluids include water, diesel oil, nitrogen foam, water with acid.

drilling and production phases of well development. While states extensively regulate permitting and production, landowners must protect themselves from excessive noise, traffic, and use of certain equipment (e.g. compression stations), among other externalities resulting from proximity to drilling activity. Further, they must also delineate legal aspects of mineral ownership and transference. Some of the lease agreement contents are described in Section 3 and are summarized in Table 2.

Lease agreements are negotiated with the owners of the mineral estate, which, in some cases, are not the inhabitants of the house located on the surface estate, or absentee lessors.[24] States often allow the mineral estate to be severed from the surface estate, and in Texas, severance is indefinite whereby the rights to the minerals may be passed through generations independent of how the surface estate is bought and sold.[25,26] Firms drilling wells in regions with more mineral severance (lessor absenteeism) may find it difficult to locate the individuals with whom they should contract. Within the state of Texas, Table 3 describes variation in likely absenteeism based on lease data in which parts of the address do not match with well locations, an indication of severed estates. While the Barnett and Permian regions have similar fractions of absenteeism, the total surface area is greater in the Permian with fewer total landowners relinquishing rights to drill (438,242 leases spread across 52 counties compared to 600,414 Barnett leases spread across 13 counties).

## 3 Data Sources and Descriptive Statistics

The analysis uses well permitting, production, and administrative data that describes when firms apply for permits to drill a well, whether or not they were granted a well density or spacing exception, whether the well is drilled under the compulsory pooling statute, and whether the well is drilled on state-owned or private property, in addition to monthly production values. These data are collected from state agencies tasked with regulating the oil and natural gas industry, including the Texas Railroad Commission and the State of New Mexico Oil and Conservation District, and Drillinginfo,[27] a data aggregator. The contract analysis uses data that describe the legal clauses written into individual leases negotiated between private landowners and firms transferring parcels of land located in Tarrant County Texas. This data originates from a combination of Drillinginfo, *The New York Times*, and the Tarrant County Clerk Office.

The well data describes important dates like the year and month that the well begins producing oil and natural gas, along with all subsequent monthly production values. Drilling costs are approximated by measures of well depth, whether the well is directional/horizontal, and lateral lengths. Each well is mapped using geographic information software (GIS), which allows me to add geographic descriptions like inclusion in particular shale/ basin regions,[28] counties, U.S. Census

[24] While some states stipulate a separate surface agreement to mitigate adverse drilling behavior, not all states do so, including Texas, putting the surface owner at the mercy of the mineral rights owners' decisions to lease.

[25] In Louisiana, a severed mineral estate automatically returns to the surface estate owner after 10 years have passed as long as there is not an active use of the minerals, like an actively extracting well.

[26] Additional details regarding the dominance of the mineral estate are described in the Appendix.

[27] Accessed through a subscription at the University of Chicago.

[28] The U.S. Energy Administration provides GIS shapefiles delineating the shale/ basin region boundaries across

tracts, and zip code regions. The top panel of Table 4 describes average log, well-level production produced by oil and natural gas wells located in Texas. It is notable that over 90% of the average production is realized during the first 24 months of production, which is the most used dependent variable. Many of the observations are horizontal wells, and the laterals are significantly longer for natural gas wells than oil wells. The last panel describes average production per square mile for oil and gas wells located in Texas and New Mexico, and the New Mexico regions appear to produce more oil and natural gas having drilled fewer laterals when the data is restricted to drilling within 100 kilometers of the state borders.

I use the drilling locations to construct other measures like wellpads, or regions in which an area of land is reserved for multiple well laterals, and proximity to existing well infrastructure and state borders. The wells are also mapped to U.S. Census tract data spanning the 1980, 1990, 2000, and 2010 decennial censuses that describe tract-level population, household, and median income estimates in regions with active oil and natural gas industry activity.[29]

Before drilling wells, firms must amass the mineral rights to all subsurface acreage from which they want to extract, and these mineral rights may be federal, state, or privately owned. The second data source describing the leasing activity that occurs before wells are drilled and is obtained through Drillinginfo. For each county, zip code, and U.S. Census tract, I use the longitude and latitudes that approximate where each lease is signed[30] to map lease locations across Texas using GIS. For each of the tracts, zip codes, and counties, I tabulate the total number of leases signed and whether the leases are likely signed by absentee mineral owners.

Finally, the contents of lease documents are extracted from pdfs that are converted to text files and text-mined for the existence of clauses that may require environmental testing, limits to noise and traffic from drilling activity, restrict which chemicals can be used to fracture a well, and clearly delineated legal responsibilities across grantors and grantees, among other concession types. Auxiliary clause data originates from two sources: the "Drilling Down" series (Urbina (2011)) published by the *New York Times* and the Tarrant County Clerk's office. Pdf files were converted to text files that were then text-mined for instances of specific language describing many types of clauses that can be negotiated into leases. Table 2b summarizes the auxiliary clauses in the data and how specific clauses are categorized into types of landowner concessions. Table 2b also reports the frequency (of 150,501 total leases used in the analysis) of specific landowner concessions like requisite *Environmental* testing (0.177) or restrictions to *Residential Streets* (0.092). The individual clauses are categorized into clause types like those restricting *Disamenities* experienced during drilling and production, or added *Aesthetic*, *Legal*, *Water* protections.

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the United States.

[29]This data is obtained using *Simply Map*, a census data user interface accessed through the Duke University Libraries.

[30]For the majority of the data, the leases are geographically defined by the abstract centroid, whereby an abstract is legal land definition established by Tarrant County Appraisal office and is roughly one to two kilometer squares. As a consequence, the lease location is more crude than matching leases to specific parcels of land using address-based string matching. Only one county, Tarrant County, has leases matched to parcels, and it is the primary focus of the contract analysis.

# 4 Conceptual Framework

Drilling oil and natural gas wells that access minerals owned by private landowners resembles land assembly problems joining adjacent, contiguous plots into one that are more broadly studied in the urban economics literature. Fragmented property rights that are smaller than the scale of economic use increase the costs to execute the desired project. In drilling, an individual well may require assembling the mineral rights belonging to upwards of one hundred private landowners in more urban and suburban settings. In theory, a firm requires cooperation among all affected landowners before a drilling project can commence. Landowners may have disutility from well exposure, perhaps related to environmental risks or aesthetics associated with wellpad operations, or they may be rent seekers, refusing to sign a lease in period $t$ with the expectation that the firm will value the lease more in period $t+1$ as the firms' costs of abandoning the project increase with each incremental and successful negotiation. Because a single landowner holding up the project thwarts the ability of the firm, regulator, and cooperating landowners to earn profits from a well extracting their minerals, state regulators have a few responses to these holdups that allow projects with enough cooperation to begin. Regulators may force cooperation among all affected landowners or they may allow firms to circumvent persistent holdout landowners through well density and spacing exceptions. The following conceptual framework begins with a simple "intent to drill" land assembly setting proposed by Buchanan and Yoon (2000) and discretized by Leonard and Parker (2016), which is based on observations by Heller (2008), and augments the model to include regulatory responses to holdup. I find theoretical evidence that firms' private incentives to drill are stronger with regulatory intervention through lower contracting costs, even for some cases when production from the regulated wells is lower, and if regulators ignore the commons problem inherent in resource extraction, these incentives can lead to over-drilling.

## 4.1 Anticommons and Contracting Costs

In the baseline model, firms drill wells that are profitable, and the profit is represented by $\pi = (1-R)pq - c - \tau N$, where $(1-R)pq$ denotes the revenue retained by a firm drilling a well with cumulative production $q$ earning a per-unit price $p$ and paying royalties to landowners at a rate $R = \sum_i r_i w_i$, where $w_i$ is the weight measuring landowner $i$'s share of land needed to drill the well.[31] Well costs, $c$, quantify the costs of labor, drilling rig rental rates, and necessary materials (e.g. fracturing fluids, well casing, etc...) to drill horizontal or vertical well laterals of varying lengths that is assumed be uniformly distributed, following the setup in Leonard and Parker (2016). In firms' profits functions, $\tau N$ quantifies the transaction cost to lease with $N$ individual landowners. It is costly for firms to identify and contract with all affected landowners, especially when there are many landowners with whom to negotiate and/or there is a high incidence of convoluted mineral ownership though severance, and these labor and search costs are lumped into the transaction

[31] They simplify the model by assuming that each landowner contributes an equal share of the acreage, so $R = \frac{1}{N}\sum_{i \in N} r_i$.

costs. In addition, there is a cost to induce all affected landowners into agreement, and these coordination costs arise in the model by allowing landowners ("excluders") to set their accepted royalty rates. Landowners request royalties $r_i$ in accordance with a Symmetric Nash Equilibrium[32] that maximizes the probability a well is drilled times the profit earned from said well conditional on drilling. To summarize the findings in Buchanan and Yoon (2000) and Leonard and Parker (2016), coordination and transaction costs increase with the number of landowners, $N$, which lowers the overall probability of drilling a well. Further, they derive an expression confirming that there is underutilization in the anticommons, which is a consequence of property rights that are smaller than the size of economic use.

When drilling requires coordination across many private landowners, should a few landowners be allowed to thwart projects by not relinquishing their mineral rights? Cooperating landowners may argue that the holdout imposes on their rights to profit from their minerals by thwarting the project, whereas the holdout, if the project is allowed to proceed, may miss out on ever profiting from their minerals as a consequence of the rule of capture. Regulators overseeing the industry are tasked with both the conservation of minerals and protection of correlative rights, even among small landowners. Regulators protect correlative rights by imposing well density and spacing exceptions that require wells be far enough away from unleased land and existing well infrastructure to limit the extraction of migratory fluids from land outside their defined (and permitted) drilling unit. Regulators' responses to holdout are largely one of two types: (1) holdout landowners are pooled into the drilling unit and profit from future production or (2) firms are granted exceptions that allow them to drill nearer to unleased property or existing wells.[33] I attempt to include the effects of these regulatory responses in the firms' and landowners' decision problems.

Under regulatory exceptions or forced pooling, the number of required individual negotiations decreases to $N' < N$,[34] leading to a well that is drilled based on modified level of production, $q'$, and transaction cost, $\tau N'$, in the profit function, $\pi' = (1-R')pq' - c - \tau N'$. Because firms negotiate fewer total leases, the landowner problem that maximizes royalties (probability of drilling x royalty payment conditional on drilling) changes, as well, and is described in (1).

$$\begin{aligned} &max_{r_i} \frac{(1 - \frac{1}{N}\sum r_i)pq' - \tau N' - \underline{c}}{\bar{c} - \underline{c}} \frac{pq' r_i}{N} \\ &s.t. \sum_{i \in N} r_i = r_i + (N - N')\bar{r} + \sum_{-i \in N', -i \neq i} r_{-i} \end{aligned} \tag{1}$$

Landowner profits are still split across $N$ landowners, so landowner $i$ receives $\frac{pq' r_i}{N}$ if the well is

[32] The strength of this assumption is addressed later in the section and is an area of future research.

[33] In fact, I hypothesize that most of these holdouts end up signing leases. Nonetheless, the coordination cost burden is reduced for firms equipped with the threat of an exception.

[34] Many states allow firms to force pool landowners once they have a negotiated with a known majority of landowners, like 75%. With exceptions, the threshold is unknown and many holdup landowners will eventually agree to sign a lease knowing that, if they do not, they will not profit from the inevitable well. Those late signers (post exception application) lose their bargaining power as the Texas Railroad Commission requires firms to extend a reasonable, take it or leave it offer to all affected landowners. For now, the model assumes that $N'$ is known for both type of regulation.

drilled. However, firms negotiate $N' < N$ fewer leases with individual landowners before pooling or applying for an exception that coops the remaining $N - N'$ landowners into the drilling unit at a royalty rate $\bar{r}$.[35] The remaining, negotiating landowners' royalties enter landowner $i$'s decision through $\sum_{-i \in N', -i \neq i} r_{-i}$ in the constraint. Based on the landowner's problem in (1), the new symmetric royalty rate is captured below in Equation (2) and the calculation details are provided in the Appendix.

$$r_i^{N'} = [\frac{N(pq' - \tau N' - \underline{c})}{pq'} - (N - N')\bar{r}]\frac{N'}{N'+1} \tag{2}$$

If $q' = q$, lower transaction costs lead to lower the coordination costs, as well, under regulatory exceptions through a lower $r_i^{N'}(q') < r_i^N(q)$ where $R' = \frac{1}{N}\sum_{i \in N} r_i^{N'}$.

How do differences in potential production outcomes across regulated and non-regulated wells affect transaction and coordination costs and, subsequently, firms' propensities to drill? To form predictions addressing this question, I relate production without exceptions to production with exceptions by introducing a parameter, $\beta \in (0, \infty+)$, where $q' = \beta q$. If $\beta = 1$, then wells with and without regulator exceptions are equally productive, on average, whereas a $\beta < 1$ suggests that wells drilled with exceptions are less productive. Substituting this relationship into Equation (2), and comparing $r_i^{N'}$ to the $r_i^N \equiv \frac{N(pq - \tau N - \underline{c})}{pq}\frac{N}{N+1}$ derived by Leonard and Parker (2016), I find that $r_i^{N'} < r_i^N$ for most values of $\beta$.[36] The results suggest that both transaction and coordination costs decrease for firms drilling wells with regulatory exceptions, which in turn, has a positive effect on the likelihood those wells are drilled even for some values of $\beta < 1$, which characterizes regulated wells as, on average, lower producers. Conversely, $\beta \geq 1$ describes regulatory exception wells that are at least as productive as non-exception wells, and on top of the production gains, lower transaction and coordination costs increase the likelihood of drilling further.

The empirical models test whether $q' < q$ or $q' \geq q$ by comparing wells that are drilled with and without regulatory exceptions in the state of Texas and wells drilled in Texas without unitization to those in other states that both force pool and unitize, which is comparable to characterizing $\beta$ under different regulator regimes. Within Texas, a $\beta < 1$ suggests that wells drilled with exceptions are lower producers, which is not necessarily a desirable outcome from the perspective of regulators tasked with optimal extraction of natural resources and minimal intrusion. The empirics also explore whether the lower production is likely attributable to lower quality resources or the more mechanical causes related to the exception process, which allows firms to drill with substandard acreage or nearer to existing infrastructure. Finally, I explore costs in contracting in Section 7 by evaluating whether leases signed at the end of the negotiation sequence do indeed have fewer beneficial concessions for landowners, as one might expect from the model.

[35] In reality, exceptions may negate compensating particularly persistent holdout landowners, reducing the number of individuals receiving $\bar{r}$ further.

[36] The results are shown in the Appendix, and the argument relies on large costs to drill a well as cited in the literature.

### 4.2 Are Coordination Costs Symmetric?

In both the baseline and modified models, coordination costs are solved assuming that landowners with exclusion rights propose royalty rates assuming a Symmetric Nash Equilibrium. This assumption embeds two simplifications. First, leases are comprised of royalties, bonuses, and non-pecuniary legal clauses that protect landowners from drilling disamenities. The current model assumes the royalty is a single index of the multidimensional contract. Second, it abstracts away from the sequential nature of negotiation observed in industry in which some landowners' minerals are more desirable. Further, there may be situations where landowners lose bargaining power because contiguous property extending in opposite directions may be substitutable from the firm's perspective. These extensions to modeling landowner behavior and the subsequent effects on negotiated outcomes are areas of future research, though Section 7 characterizes the quality of the contracts negotiated with and without regulatory exceptions along many dimensions using reduced form empirical specifications.

## 5 Technology Trends

Industry technology took a significant leap between 1999 and 2003 after a combination of private and public experimentation led to commercially viable wells that extract from tight shale formations (through large scale hydraulic fracturing techniques) and located beneath densely populated regions (through large horizontal laterals), in addition to other improvements.[37] With these changes, firms could access new resources; however, these changes likely increased the need for well density and spacing exceptions, as well. Figure 1 documents the frequency of Texas exceptions through time, noting the technology change with a red line. The gray line denotes gas wells drilled with exceptions while the blue denotes oil wells, where the latter peaks in an earlier period, which is consistent with a high level of horizontal drilling described in Figure 2. Figure 2 demonstrates a nearly perfect relationship between the frequencies of exception wells and horizontal laterals, suggesting horizontal laterals necessitate exceptions. However, it is important to note that the definition of horizontal lateral changed significantly over time, as demonstrated in Figure 3, where the black and gray lines describe mean lateral lengths through time. After the technology changed, lateral lengths surged, which is consistent with the industry story-line. Drilled regions also became more populous over time as demonstrated in Figure 4, and this population change most affected natural gas drilling. As described through the model, changes in population density lead to change in contracting costs through more negotiation partners. This section explores the relationship between population density and well production outcomes, suggesting that exception wells are most likely drilled in otherwise productive regions where they face greater contracting costs.

The following empirical model explores the temporal changes in drilling behavior and outcomes in response to these aggregate technology changes that were gradually adopted between 1999 and

[37] Other improvements include the combined fluids and propants used to fracture the wells and facilitate movement of the oil and natural gas through otherwise impermeable strata, and three dimensional seismic surveying techniques.

2003, and the model is informed by analyses studying the aggregate effects of Medicare in Finkelstein (2007). Technology changed at roughly the same time for all producers, altering the market as a whole. However, areas overlaying tight shale and/or underlying urban or suburban populations benefited more than those with neither characteristic. The following empirical model explores the changing relationship between high cost areas and production and measures a change in the relationship before and after new technology is introduced.[38]

The empirical strategy compares changes in well production outcomes in parts of Texas where leasing costs are higher to areas with lower levels, since these high cost areas are located over very valuable resources post-technology. The demographic data characterizing contract costs is not randomly assigned across Texas, so the empirical model asks whether there a trend break in the relationship between these contracting cost factors and production before and after the technology is introduced. Equation (3) describes a model in which I estimate separate effects of different regional characteristics, $Z_{mt}$, across years of drilling in the data, and I measure differences in trends before and after the technology change.

$$log(\sum_{i \in m} \sum_{p=1}^{24} q_{itp}) = \alpha_c + \delta_t + \sum_{t=1980}^{t=2014} \lambda_t Z_{mt} \mathbb{1}_t + \beta X_{tm} + \epsilon_{tm} \tag{3}$$

The model is estimated separately for oil and gas wells, and the dependent variable is the log of the sum of all oil (gas) produced by wells beginning to produce in a specific month of year $t$ that are located in zip code $m$.[39,40] The model controls for county level unobservables through estimating fixed effects, $\alpha_c$, market-level shocks by estimating year fixed effects, $\delta_t$, and average, regional well characteristics of wells drilled in period $t$, or $X_{jtm}$.

The primary coefficients of interest are the $\lambda_t$'s that measure the pattern describing the relationship between well production and contracting cost variables, comparing areas where the new technology likely more valuable to areas where it is less. Figures 5 and 6 plot $\lambda_t$'s and confidence intervals representing the trending effects of old house frequency, household counts, counts of lessors and absenteeism, and percent of the population that is Hispanic on oil and natural gas production outcomes, respectively. Additionally, the dashed lines trace the average cost characteristics of areas drilled between 1980 and 2014, which increase with passing time, sometimes dramatically breaking trend before and after the adoption period, as well.

Table 5 reports differences in coefficients before and after the change in technology for each independent variable plotted in Figures 5 and 6. The slope differences characterize the trend changes in leasing costs before and after the technology change, and they compare slopes two, five,

[38] It would perhaps be interesting to try this exercise on U.S. level data in a future iteration.

[39] Levels impose that outcomes grow by the same amount each period regardless of well size, of which there is considerable variation. In general, the oil and natural gas production levels are heavily right skewed suggesting that a log-linear model is a better fit for all production analyses going forward.

[40] The data is stacked such that there is a month and year observation of cumulative production from wells drilled in that period for each region $m$. Geographic region is defined as a zip code because the regional characteristics, $Z_{mt}$, are extracted from the U.S. Census data reported by zip code.

and ten years before and after in addition to a comparison across the five years removed.[41]

$$\Delta_5 \equiv (\lambda_{2005} - \lambda_{2000}) - (\lambda_{1998} - \lambda_{1993})$$

While I report trend changes two year before to two years after, interpreting estimated changes comparing five and ten year intervals seem more relevant given the fuzzy adoption period spanning around three years. Oil wells exhibit the greatest trend break when comparing the long term trends, or ten years before 1999 to the 10 years after, while gas wells exhibit the greatest break comparing the five years before 2001 to the five years after. This is likely a consequence of the significant decrease in natural gas prices that occurred around 2008 and is encompassed by the post ten year period, and the panels in Figure 6 all reveal a second trend change at about that time.

Focusing on an independent variable affecting both oil and gas production, areas with total household count were increasingly productive for oil wells and peaked near 2000(1). It is also notable that the average number of households in oil well locations is slightly upward sloped throughout the analysis period. There is also an upward trend to drill in areas where a greater fraction of lessors are absentee, and after technology, those areas are increasingly more productive, reversing a downward trend from before the technology adoption.

The relationships between contracting costs and gas well production respond more sharply to technology adoption as evidenced by the top four panels of Figure 6. Natural gas wells were not productive in higher density areas until the technology change, at which point, areas with more total households become significantly more productive than areas with fewer.

Generally, areas with greater drilling costs are more productive post-technology, and the pattern is more consistent for natural gas production. The change in technology coincides with increased regulatory exception applications and approvals by the Texas Railroad Commission as evidenced by Figure 1 As noted, regulatory exceptions can be a mechanism to reduce contracting costs, so as it becomes feasible to drill in urban and suburban regions, there is greater incentive to use exceptions as a means to lower contracting costs. Oil extraction may be less responsive to this cost margin because the technology potentially resulted in an alternative response by allowing firms to "re-drill" existing wells in previously active regions like the Permian, giving life to a new round of profitability, and these areas are much less populous than regions near or overlaying shale gas.

## 6 Efficient Well Production

As noted in Section 5, new technology likely increased contracting costs by increasing access to tight shale and resources located beneath more populous regions, greatly fragmenting the property rights and increasing the count of firms' pre-drilling negotiations. Prior literature notes that greater fragmentation (or exclusion rights) may lead to under-use by thwarting otherwise viable projects, and in the land assembly literature, holdouts are a common culprit. To solve the anticommons problem in oil and natural gas leasing, regulators force holdouts into agreement given there is

[41] Comparing the slopes from 1989 to 1994 to that of 2004 to 2009.

enough voluntary cooperation among non-holdout landowners. As described in Section 4, these policies reduce contracting costs by requiring fewer negotiations and less overall cooperation. The following empirical analyses use existing wells to understand whether production differs under variants of these eminent domain-like policies used in the oil and natural gas industry, which affect firms', landowners', and regulators' mineral profits.

Many states force pool landowners into drilling units, which reduces the number of required negotiations and all landowners are compensated with future royalties. Texas differs and grants well density and spacing exceptions that force holdout landowners into agreements or circumvents them altogether. Both of these policies are designed to allow projects that are desirable for a majority of affected parties, but is excluding holdups (thwarting their ability to negotiate) costly? Since there are two policies, I use two empirical strategies to bound the regulatory costs realized through changes in actual well production. Beginning with Texas, Section 6.1 details a method to identify the negative effect of well density and spacing exceptions on aggregate and marginal well production. Firms drilling in Texas have more freedom to choose where to drill and assemble the necessary mineral rights. Given the unit satisfies state-specified spacing and density rules, the TRC approves drilling permits. Wells drilled with exceptions are allowed to be drilled nearer to unleased property, nearer to existing wells, or with substandard acreage. The estimated parameters suggest a negative effect of regulation targeting the anticommons problem alone.[42]

The upper bound from comes from estimating a border discontinuity effect of drilling wells in states the regulate the anticommons through force pooling landowners and the commons through unitization that is presented in Section 6.3. The border discontinuity estimates capture an incremental value of also coordinating firms' spatially proximate drilling activity through unitization. These estimates confirm related evidence established in Libecap and Wiggins (1985) and Balthrop and Schnier (2012).[43]

Finally, Section 7 documents evidence that suggests exception wells' proximity to existing infrastructure may explain why these wells produce less.

### 6.1 Aggregate Production

The following model of aggregate production divides the Texas well observations into square mile blocks of land, denoted by $M$, and sums the production from all wells drilled in a particular

[42]Well-level estimates that instrument for well density and spacing exceptions are described and reported in the Appendix. The conclusions are similar, substantiating the notion that exception wells are marginally less productive, and OLS estimates are positively biased. The instruments describe contracting costs (and instruments describing potential exception costs generate estimates with similar signs), and the exclusion restriction assumes that regions with higher contracting costs are not correlated with the quality of oil or natural gas production. A violation would occur if those wells were only drilled because they were lower cost (and thus have lower production). While I think there is substantial evidence that exception wells are drilled in more populous or well dense regions that are not low-producing regions, it is tough to defend this exclusion restriction fully.

[43]The well level estimates that most resemble the strategy in Balthrop and Schnier (2012) using the Texas/Oklahoma border are reported in the Appendix.

square mile block beginning in 1940.[44] The primary dependent variables describe the natural log of area-level, cumulative oil or natural gas produced during the first 24 months of well production.[45] Focusing on the first 24 months allows the analysis to encompass the primary producing period for oil and natural gas wells based on the wells' natural decline curves; however, estimates are not sensitive to using the total, observed well production. The model regresses the log of the cumulative well production per square mile on a measure of the number of well exceptions granted in a simple ordinary least square (OLS) model, and Table 6a reports estimates of $\alpha$ from a simple ordinary least squares model described in Equation (4).[46]

$$log(\sum_{w \in m} \sum_{p=0}^{24} q_{wp}) = \alpha_0 + \alpha \sum_{w \in M} \mathbb{1}_w T^{Except} + \epsilon_m \tag{4}$$

The first column reports the effect of exception wells on production of oil, the second reports estimates for gas wells, and the third restricts the gas well sample to those wells drilled in Fort Worth, overlaying a highly productive shale gas region. The effect of exceptions is positive for all well types, which suggests that drilling exception wells allowed firms to increase overall productivity across Texas.[47] These estimates may suffer from omitted variable bias in which firms may be more prone to apply for (and be granted) well density and spacing exceptions in regions with higher expected productivity, upward biasing the OLS estimates. Firms may find it advantageous to apply for an exception when doing so lowers their contracting costs or decreases the time to begin drilling through another mechanism. Further, as noted, exceptions may be needed to drill a well nearer to existing well infrastructure, and one can imagine that firms propose smaller drilling units, even if they are closer to competitors' wells, in prolifically producing regions. Conversely, firms may only drill a well if they are able to lower the contracting costs by being granted an exception, which would downward bias the results. To resolve some of the omitted variable bias, I re-estimate the models including spatial fixed effects, where space is defined as the two square mile region containing the square mile blocks of aggregate production. The assumption is that the resource quality and population characteristics should be similar within a two-square mile block, further isolating an average effect of exception wells on total, square mile production within spatial groups. Estimates reported in Table 6b suggest that the spatial fixed effects are particularly consequential for estimating the effect of exceptions on gas production as the estimates are fraction of of the OLS estimates without spatial fixed effects. The estimate is roughly $\frac{1}{4}^{th}$ the OLS estimate among wells drilled in the Fort Worth Basin. In all cases, controlling for unobserved spatial heterogeneity

[44] Only the Permian has well dating back to 1940, and the estimates are not sensitive to summing well production beginning at a more recent date.

[45] Well observations with production beginning after 2014 are dropped because I am not able to observe the first two full years of production.

[46] Estimates are actually estimated as an instrumental variable model because there may be measurement error in how I measure well exceptions. I have two sources of exception information, combined to construct this data, and instrument one exception measure with another to mitigate the measurement error. Estimates do not differ in a substantial way controlling for measurement error or not.

[47] These estimates are not sensitive to larger spatial resolutions that measure production coming from two and five square mile blocks of land.

lowered the OLS estimates, suggesting that the OLS estimates are positively biased.

The second model of aggregate production is concerned with estimating the marginal well productivity per square mile in addition to the marginal effect of those wells being exception wells using the model in Equation 5.

$$log(\sum_{w \in m} \sum_{p=0}^{24} q_{wp}) = \alpha_0 + \alpha_1 \sum_{w \in M} \mathbb{1}_w + \alpha_2 \sum_{w \in M} \mathbb{1}_w T^{Except} + \epsilon_m \tag{5}$$

Table 7a reports estimates from a simple OLS that includes a count of oil and gas wells, in addition to the count of exception wells, drilled in a given square mile region. For each liquid type, I report estimates that do and do not account for year-level changes in production per square mile. The estimates suggest that each additional oil or gas well has a positive effect on the total oil or gas recovered ($\alpha_1 > 0$), respectively, while exception wells have a negative effect on production ($\alpha_2 < 0$), except when restricting the gas wells to those located in the Fort Worth Basin. Concerned with the same omitted variable bias discussed with respect to the model described in Equation 4, Table 7b reports results estimated by Equation 5 with two-square mile fixed effects. Estimated effects of exceptions decrease in magnitude for oil wells and increase in magnitude for gas wells. The Fort Worth wells change sign altogether suggesting that they too produce less per marginal well drilled with an exception when controlling for unobserved spatial heterogeneity.

Taken together, the results describing the effects of exceptions on aggregate production suggest that, while total production may be greater in regions with exceptions, the marginal productivity of each well drilled is decreasing. These results are robust to estimating the models that control for years of production, which also estimates space by year fixed effects, production only occurring in later periods, the diminishing returns of each additional well, and different levels of spatial resolution both to measure aggregate production and control for spatial, unobserved heterogeneity.

### 6.2 Instrumental Variable

The aggregate analysis relating well exceptions to observed production per square acre mitigates omitted variable bias by controlling for a high resolution of spatial fixed effects. This section proposes an additional approach to mitigating endogeneity in the regressors by introducing instrumental variables to a well-level analysis of production.[48]

Equation (6) describes the cumulative sum of production from well $i$ during the first $T$ months as a function of whether firms are granted a permit to drill having also been granted a well density or spacing exception, denoted as the treatment in this setting, $T_i^{except}$. Other controls include well costs, $c(X_i; \delta^{qx})$, period fixed effects controlling for the first year of production, $\mu_{t_0}$, spatial fixed effects, $\lambda_m$, and an error term, $\eta_i$. A traditional ordinary least squares specification assumes that there are no unobserved shocks to a well's production outcome that covary with the propensity to

[48]The Appendix reports IV results using the aggregate data strategy measured at the zip code level (because the instrumental variables are measured at the zip code level), and I find comparable results.

apply for (and be granted) a density or spacing exception.

$$log(\sum_{t=0}^{T} q_{i,t}) = \theta_0 + \theta_1 T_i^{except} + c_i(X_i; \delta^{qx}) + \mu_{t_0} + \lambda_m + \epsilon_i \tag{6}$$

As noted in Section 6.1, of primary concern is that wells drilled with exceptions are more common in areas with greater expected productivity, or $T_i^{except}$ in Equation 6 is endogenous to well production, which upward biases the OLS estimates reported columns (1) and (3) in Table **??**. The opposite concern is that more exception wells are drilled in areas with lower expected productivity that suggests a selection on wells that are only drilled because they are granted "cost lowering" exceptions through fewer negotiations, thereby downward biasing the OLS estimates. Appealing to the results in Section 5, the regions with high contracting costs are also regions with a lot of natural gas production, in particular, suggesting that firms are drilling in these productive regions even when the contracting (or well design) costs are high. To mitigate these costs, they apply for and are granted exceptions.

A measure predicting the likelihood an exception application is accepted would be an ideal instrument; however, most applications are approved even among those approved after a formal hearing in Austin.[49,50] Instead, I propose two instrument types: (1) measures contracting costs and (2) measures of exception costs. Both of these costs are administrative and likely not correlated with the quality of what is stored in and extracted from the ground, which allows me to think of them as acting on final production through the exception. The instrumental variable results that are reported use *Fraction of Absentee Lessors* and *Percent of Owner Occupied Houses*. Each is measured at the U.S. Census zip code level and are summarized for Texas in Table 4.[51] The first, oil well instrument, *Fraction of Absentee Lessors* in a zip code, measures an increased cost to lease whereby mineral ownership is observably not the same as surface ownership. Absenteeism approximates the fraction of estates in which the mineral rights are severed from from the surface rights, which usually means that the mineral rights owners do not live in the house sitting on the targeted properties. The variable is constructed by comparing the zip code in which the leases are mapped to the zip codes listed in the lessor addresses of leases signed across the Permian, Barnett, and Haynesville Shale regions, and non-matching zip codes are declared to be likely absentee. Because firms are required to negotiate with mineral rights owners only, absentee owners are more costly for firms to find and sign leases with as they must trace mineral ownership by evaluating historical deeds for each severed estate at the county clerk offices. Severing estates is common practice in Texas with large swaths of privately owned minerals and a historically active oil and natural gas industry. Table 3 summarizes the frequency of absentee lessors by drilling region. The

[49] Behrens (2011) cites the increased incidence of exceptions across time and notes that most applications are accepted. I confirm these observations with the TRC docket data describing applications and acceptances.

[50] Instrumenting $T_i^{except}$ with the distance to Austin is not precise, though the sign of the effect is negative.

[51] Specifications are robust to different instrumental variables including the zip code-level median household income, the fraction of individuals with high school diplomas, the fraction of households speaking Spanish as their primary language, changes in population density, frequency of old houses (built before 1936), and the frequency of absentee lessors.

rate is about half in the Permian; however, the total number of leases is much less suggesting that a well requires many fewer negotiations than drilling the Barnett where there is a comparable rate of absenteeism and more total leases spread across a fraction of the counties. The second, gas well instrument, *Percent of Owner Occupied* houses, approximates the likelihood that mineral rights owners are living in the house built on the surface estate, as well, as reported across the 1980, 1990, 2000, and 2010 decennial censuses.[52]

Equation (7) describes the first stage relationship between the treatment, or wells drilled with a well spacing or density exception, the instrumental variables, $Z_{im}$ describing market density and lessor absenteeism, and the drilling costs, and Equation (8) describes the second stage equation that produces an unbiased estimate of the effect of treatment on the cumulative production outcomes, which assumes that $E[\epsilon_i, v_i] = 0$ for well $i$ located in market $m$.

$$T_i^{except} = \alpha_0^{rz} + \alpha_1^{rz} Z_{im} + c_i(X_i; \delta^{rz}) + v_i \tag{7}$$

$$\sum_{t=1}^{T} q_{i,t} = \alpha_0^{qz} + \alpha_1^{qz} \hat{T}_i^{except} + c_i(X_i; \delta^{qx}) + \mu_{t_0} + \lambda_m + \epsilon_i \tag{8}$$

A potential violation is that individuals may have severed their estates long ago based on an expectation that their minerals are profitable. Areas overlaying tight shale formations had low expected productivity before wide adoption of combined large-scale hydraulic fracturing and horizontal drilling techniques. However, Table 3 isolates the frequency of absentee lessors of the Barnett and Haynesville, tight-shale formations, and one can see that there is wide variation in absentee frequency across counties with similar expected productive outcomes. Anecdotally, counties like Tarrant County have fewer absentee lessors because landowners did not foresee extraction in such a densely populated, tight-shale region. Tarrant has been a productive region and is only now accessible through recent changes in technology.

### 6.2.1 IV Results

The effect of *Exception* describes a benefit or penalty from drilling wells in irregular drilling units on one or other dimension, i.e. too close to existing well infrastructure, too close to unleased property lines, or comprised of a substandard acreage. The primary dependent variables describe the natural log of well-level, cumulative oil or natural gas produced during the first 24 months of production, and the estimated relationships are robust to measures of cumulative production during the first three and twelve months along with the wells' total, cumulative production as reported in the Appendix. Most of the control variables are fixed effects that describe when a well beings producing oil or natural gas and where the well is located, which soak up unobserved heterogeneity. To mitigate bias that may result from unobserved, market-level shocks I control for the first year of

[52]The sign of estimates using the count of absentee lessors, the changes in the population density, and the fraction of homes built before 1936 by zip code render estimates with consistent signs to the preferred specifications. The preferred estimates use an instrumental variable that is sufficiently random.

production by including a set of year fixed effects.[53] Including year fixed effects soaks up market-level shocks, like changes in oil and natural gas prices, that may influence a firm's decision to proceed near the point in time when they are deciding to drill.[54] In addition to controlling for the specific well locations by including longitude and latitude spatial coordinates, I estimate shale fixed effects describing whether the well is drilled in a location overlaying a tight-shale formation (oil or natural gas). Shale fixed effects control for unobservable variation in the type of resource accessed, whether from a tight shale strata or traditional reservoir. Finally, spatial fixed effects that describe drilling oil wells from a common field or drilling gas wells from a common twenty-mile block of land soak up more general and unobserved spatial characteristics that may influence the productivity of a given well.[55]

Estimates in Table 8 describe the ordinary least squares relationship between *Exception* and cumulative oil and natural gas production in the first two columns, and the last two columns corrects the potential endogeneity bias by using instrumental variables. Columns (1) and (3) of 8 report estimates from models that do not include the more general spatial fixed effects, while columns (2) and (4) estimate coefficients from models that include both shale and more general spatial fixed effects. Table 9 describes the first stage and reduced form estimates of the proposed oil and natural gas well instrumental variables.

Ignoring potential endogenity, column (1) of Panel 8a estimates suggest that oil wells produce 25% more cumulative oil when drilled after applying for and being granted an *Exception*. However, an estimated model that controls for endogeneity suggests quite the opposite story whereby *Exceptions* lead to an 64% reduction in cumulative production as suggested by the coefficient -1.029 (0.229) in Panel 8a, column (3). The estimates and interpretations for the models of oil well production do not differ much depending on whether the models are estimated with wells drilled after 1990 (comparing columns (3) and (4) in Panel 8a).

Panel 8b describes the estimates from OLS and 2SLS models of natural gas production. Columns (1) and (2) report the estimated effects of *Exceptions* that ignore potential endogenity. The column (2) estimate suggests that *Exceptions* wells produce 9% more, which does not differ wildly from the response estimated among oil wells. Columns (3) and (4) report estimates that control for endogeneity bias using the preferred instrumental variable, *Pct. Owner Occupied* houses in a zip code. Focusing on estimates that use the full data sample, gas wells drilled with exceptions are roughly 53% less productive than those wells drilled without.

Using the summary statistics in Table 4 and estimates in 8, a 64% less productive oil wells suggests a loss of 2,468 barrels of oil, and a 53% less productive gas well suggests a loss of 68,585

[53]The specifications are robust to the addition of a flexible time trend function that capture dependency across years.

[54]The control variable analysis in the Appendix demonstrates that estimates are similar when directly controlling for oil and natural gas futures (monthly averages).

[55]Table **??** in the Appendix reports instrumental variable estimates using ten-mile blocks, oil or natural gas field identifiers, and county fixed effects, and the estimates are largely consistent. Counties are roughly four times the size of the twenty mile spatial blocks, and the coefficient for *Exceptions* on oil wells is positive yet insignificant when estimating the models with larger scale spatial fixed effects.

cubic feet of natural gas. Added to that the range in oil prices during the period, reaching as low as $20/bbl and up to $120/bbl, the loss in dollars ranges from $49,379 to $296,276 for the first 24-months of cumulative production of an average well.[56] Gas price variation, which ranges from roughly $2 to $10, leads to losses of $137,171 to $685,857.[57]

Concentrating on the first stage results that are reported in Table 9a, estimates in columns (1) and (2) suggest that wells drilled in zip codes in which there is a large fraction of absentee lessors are more likely to be drilled with an *Exception*, and the relationship persists when restricting the data to wells drilled after 1990. Moving horizontally, I find there is a negative, reduced form relationship between a the *Fraction of Absentee Lessors* and well productivity. Because the preferred model is exactly identified, I am able to derive the instrumental variable relationship through the ratio of $\frac{\beta_{fs}}{\beta_{rf}} = \frac{0.212}{-0.218} = -0.97$, which is comparable to the estimated $-1.029$ from column (4) of Table 8a. Returning to column (4) of Table 9b, I estimate a negative relationship between the prevalence of owner occupied houses and *Exceptions* (-1.667 (0.237)), and there is an overall positive relationship between the *Percent Owner Occupied* houses and cumulative production (1.242 (0.603)).

The analysis uses well production data that begins around 1976 and extends till 2014 (truncated to ensure there are at lease 24 months of observed cumulative production for each well). During this time period, technological innovation in the industry transformed oil and natural gas extraction (and supply), whereby firms could extract from tight-shale formation located beneath densely populated regions. The full effect of this transformation is realized by at least 2005. In 2008, oil and natural gas prices decreased significantly. As a consequence, Table 10 describes IV estimates using subsets of the data that are restricted to certain years of production. Estimates from the fixed effects specification and restricting the data to those wells drilled after 1990, 2000, 2005, and 2008 reveal relatively consistent causal effects of *Exceptions* on cumulative oil and natural gas production.

The Appendix reports estimates that demonstrate robustness to different measures of well productivity, including levels, restrictions to horizontal wells, inclusion of control variables and firm fixed effects, inclusion of an effect for wells drilled to extract from state owned minerals, and exempting state-owned wells, in addition to estimates derived from different instrumental variable choices. Finally, the Appendix reports robustness to estimating different spatial fixed effects and using the log of well revenues generated during the first 24 months of production.

### 6.3 Border Discontinuity Models

The border discontinuity is designed to build on the results estimated in Section 6.1, evaluating the differences in aggregate production from drilling wells in Texas versus New Mexico, where the state requires that firms coordinate their drilling effort more through unitization. Similar to a

[56] The average well in the data is profiting from approximately $76,838 to $461,032 over the first 24 months. The data is heavily skewed, however, and the largest wells are profiting between 1 and 16 million over the first 24 months.

[57] The average gas well is profiting from approximately $261,857 to $1,309,289 over the first 24 months. Similar to oil wells, the gas well sizes are heavily skewed, and the largest wells are profiting between 5 and 25 million in the first 24 months of production.

traditional border discontinuity design, the running variable measures the distance between the square mile blocks of land and the state border.[58]

In a border discontinuity analysis, one may worry about other state-level differences confounding the estimated differential production from wells located in Texas compared to those in New Mexico. The border discontintuity specification may suffer from omitted variable bias resulting from other unobservable state differences that lead to less productive Texas wells, or selection bias in which firms may decide to drill certain types of wells in a particular state. Severance taxes are similar in both states, and population characteristics are very similar in both states along the border as evidenced in Table 11. Another confounding factor spanning state borders may be pipeline infrastructure used to transport oil and natural gas from gathering lines a market for sale.

In addition to the main effect of location in New Mexico, $\beta_1$, $d(\bar{dist}, \mathbb{1}^{NewMexico}; \gamma)$ is a quartic function of the distance between the square mile block and the state lines in addition to interactions between the quartic distance function and being located on the New Mexico side of the border.

$$log(\sum_{w \in m} \sum_{p=0}^{24} q_{wp}) = \beta_0 + \beta_1 \mathbb{1}^{NewMexico} + d(\bar{dist}, \mathbb{1}^{NewMexico}; \gamma) + \eta_m \tag{9}$$

Because New Mexico shares an eastern and southern border with Texas, I report estimates that divide the observations and run separate models comparing square mile blocks just along the border. The main specifications limit the analysis to wells located within 100 kilometers of the border, though the models are robust to smaller buffers. Beginning with Table 12a, New Mexico regions are producing more aggregate oil and natural gas than regions in Texas without controlling for spatial fixed effects. Table 12b includes spatial fixed effects that controls for unobservable heterogeneity along the opposite dimension of the border direction and subsequent distance variable.[59]

### 6.4 Well Characteristics

Are the regions with more exceptions or locations in New Mexico observably different? In Equation (10), I propose estimating similar models that, within Texas, relate exceptions to measures of well density and firm competition and, separately, relate them to being located in New Mexico. The measures of well density and firm competition are represented by $Z_m$, where density is the count of oil or gas wells or the count of wellpads in a square mile region. Firm competition is measured as the count of active firms drilling wells in the square mile region. Similar to the production

[58] Well level estimates of the border discontinuity are presented in the Appendix. The well-level analysis is robust to different parametric and non-parametric (local linear) model specifications in addition to different distance bandwidths (from the border). The well-level estimates most resemble the border discontinuity estimate for oil wells located along the Oklahoma and Texas border by Balthrop and Schnier (2012). My well level estimates for oil wells are in line with their estimates, and I am also able to measure an effect for gas wells. Finally, the analysis ordinary included a comparison between Texas and Louisiana; however, the estimates suggest a greater response to severance tax incentive differentials across the two states that are described in Table 1 and is reserved for a separate analysis.

[59] The East/West border has a running variable measuring proximity between the square mile blocks and state lines that moves in the east/west direction. The spatial fixed effects control for 5 mile latitude blocks that control for the north/south direction.

models, these models are estimated controlling for unobserved, spatial heterogeneity by estimating two square mile block fixed effects, or $\delta_{m'}$.

$$\begin{aligned} Z_m &= \alpha_0 + \alpha \sum_{w \in M} \mathbb{1}_w T^{Except} + \delta_{m'} + \epsilon_m \\ Z_m &= \beta_0 + \beta_1 \mathbb{1}^{NewMexico} + d(\bar{dist}, \mathbb{1}^{NewMexico}; \gamma) + \delta_{m'} + \eta_m \end{aligned} \tag{10}$$

Within Texas and reported in Table 13a, estimates suggest that areas with exceptions wells, in general, contain more oil and gas wells. Further, exception areas also have more competition, as suggested by the positive and significant coefficients. Straddling the Texas and New Mexico border, Table 13b reports that New Mexico regions have fewer oil wells and wellpads and more competition, as well. Tables 14a and 14b estimate the model with average well characteristics by year, which allows me to control for industry changes through time. The estimates in Table 14a confirm findings in Table 13a that suggest exception regions are more well-dense with the added observation that exception regions have more horizontal drilling and, on average, slightly longer laterals. Table 14b estimates the same relationships comparing the Texas to New Mexico wells and finds no difference in well density and firm competition; however, the estimates suggest that New Mexico has more horizontal drilling and longer laterals.

The Appendix includes results based on well-level cost measures, estimates describing the relationship between being an exception well (within Texas) and horizontal lateral length or the minimum distance to the nearest well at the drilling date. Exception wells, on average, have longer horizontal laterals and they are located nearer to existing infrastructure. The same models are run comparing wells along the Texas/New Mexico border, and I find that Texas wells, on average, have shorter laterals than wells in New Mexico. Further, the average distance between new and existing wells are statistically indistinguishable across the border; however, the distances are greater between the largest wells in Texas.

## 7 Contracting Costs

The final empirical analysis focuses on individual leases signed across Tarrant County, Texas, an urban region overlaying the Barnett, tight-shale formation. I am interested in understanding whether there is a measurable difference in the quality of leases signed near to the date a well density or spacing exception is filed with the Texas Railroad Commission (TRC). As noted through Figures 1, 2, and 3, there has been an increase in the number of well spacing and density exceptions granted by the TRC, which is likely a consequence of developments in horizontal drilling. Further, Figure 4 describes a change in population density. Wells drilled horizontally and/or in regions with more total households require firms to negotiate with more small landowners, some of whom may decide to hold out and not sign a lease. Firms desiring to drill the well, regardless of missing or holdout landowners, approach the TRC and apply for an exception. The TRC stipulates that firms must make reasonable offers to the landowners in question, and all affected landowners must be

notified of the pending exception, which grants them up to thirty days to contest it in a hearing. Many times the exceptions go uncontested, and it is likely that holdout landowners eventually sign the offered leases to receive their share of well profits.[60]

The simple models described by Equation 11 capture whether leases signed near the date at which firms apply for the well spacing and density exception contain fewer landowner concessions by estimating $\beta_2$. Conceptually, one might think that lease offers from firms are of minimal quality to satisfy the TRC's standard of "reasonable" once the exception has been filed, and that landowners feel compelled to accept the offer to ensure they monetarily benefit from a well that will inevitably be drilled.

$$quality = \beta_0 + \beta_1 \hat{HHI} + \beta_2 T^{except} + \beta_3 X_i + \mu_t + \eta_{it} \tag{11}$$

Table 15 reports estimates that suggest leases signed in the period when firms file a well spacing and density exception with the TRC have fewer landowner protections, potentially diminishing landowners' bargaining power. Each column reports the results of separate regressions that measure lease quality on the observable parcel characteristics, a firm-level measure of market structure, year fixed effects, and a dummy that indicates the lease was signed in the same month that the well spacing and density exception was filed. The market structure, $\hat{HHI}$ is instrumented using distance measures between the firms' local offices and the Tarrant County Clerk (TCC) office, where the leases are filed, and between the lease location and the TCC. Finally, I cluster the standard errors at the wellpad level to capture any spatial correlation across wells drilled in close proximity.

The variable of primary interest is the effect of exceptions, $\beta_2$, which is negative and significant for most definitions of lease quality. These relationships suggest that leases signed in the same period in which an exception is filed have fewer landowner concessions, and on average, landowners appear to receive 30% fewer concessions in their contracts compared to those leased for non-exception wells. The estimated relationship for the royalty rate is small and positive, and the magnitude of the effect is less and 1%. However, there is merit in asking whether there is a trade-off between pecuniary and non-pecuniary contract terms at the end of the negotiation sequence, which is an area of future research. In general, the negative relationship may result because firms, upon filing, are required to extend reasonable offers to landowners prior to being granted the exception. Firms do not likely have incentive to grant more landowner concessions when satisfying this legal requirement, and landowners likely will accept the offers anyway in order to receive compensation from the future well.

## 8 Policy Effects on Profitability

The empirical analysis reveals that technological progress in the industry increased overall productivity, substantiating the overall effects of the shale boom on domestic resource consumption and oil and natural gas price responses observed over the last 10 years. With technological inno-

[60] As mentioned in Section 2, with well spacing and density exceptions, landowners without leases may have their mineral extracted using a lateral that abuts their property without compensation.

vation came increase suburban and urban drilling, areas with greater coordination (leasing costs) pre-drilling. Regulators tasked with the conservation (and efficient extraction) of natural resources and the protection of correlative rights

The effects of exception wells on total production (0.088 for oil and 0.197 for gas) reported in Table 6b suggest a gain of 775.8 Bbls of oil and 23,285 MCF of natural gas. The gains per acre are between $24 and $145 for oil and $72 to $363 for natural gas, which is split between firms and landowners where landowners earn 22% on average. Scaling by the number of square miles used to estimate the models, exceptions represent a gain of $1.5 to $9.7 million from oil and $2.7 to $13.6 million from natural gas (using a rough range of $20 to $120 per barrel and $2 to $10 per MCF). To scale the marginal effect of exceptions on total production occurring within a square mile, I refer to estimates in the first columns for oil (-0.066) and gas (-0.072) wells, respectively, in Table 7b for the back of the envelope calculations. The change in production per square mile for wells drilled with an exception and beginning in 1980 and beyond is -538 Bbls for oil wells and -7,428 MCF for gas wells. As a consequence, the change in profits per acre are roughly -$101 to -$17 for oil wells and -$116 to -$23 for gas wells, which is roughly 50% and 40%, from oil and gas respectively, less profit per incremental exception well. These percent decreases are comparable to those predicted by the instrumented well-level estimates. Scaling these numbers by the count of all square miles of drilling in the study and by the range in oil and natural gas prices, exceptions may lead to an loss of 1.1 to 6.7 million from total oil production and $0.87 to $4.4 million from total natural gas production. Combining the effects of the aggregate and marginal productivity responses to eminent domain, I find that the net aggregate gain is dissipated with more than one oil exception well per square mile and more than three gas exception wells, leading to overall net losses from the Texas policy.

Using a similar methodology to evaluate the border discontinuity analysis, I convert estimates reported in the first column of Table 12b (0.854 for oil and 0.538 for gas) into approximate gains and losses from drilling in a state with unitization. The aggregate border effects are estimated with a dummy characterizing whether the square mile is located in New Mexico in order to characterize the value of regulations addressing the private property rights and coordinated drilling simultaneously. The change in production per square mile in New Mexico is an increase in 194,574 Bbls of oil and 1,993,056 MCF of natural gas. Converting the production units into dollars, an acre in New Mexico earns between $6,080 to $36,482 from oil production and $2,591 to $12,957 from gas production. Finally, using the count of square mile units used to estimate the models, these estimates translate into an overall gain of $218 to $1,308 million from oil production and $36 to $183 million from natural gas production.

In summary, the aggregate gain and marginal losses from drilling exception wells in Texas suggest that exception wells increase total extraction, but at a decreasing rate by further diminishing the returns from the marginal exception well. Perhaps one can attribute the marginal decrease to greater well density and firm competition as suggested by estimates in Table 13a. Paired with the gains from drilling wells in a state that unitizes drilling decisions, there are potentially significant

gains to regulating drilling behavior as is common in New Mexico, which is further confirmed by the results in Balthrop and Schnier (2012).

Finally, these analyses do not address landowner costs of drilling that are internalized through lower property values and risks associated with proximity to traditional or hydraulically fractured wells. Existing hedonic literature has proposed a range of values relevant to a more complete cost benefit study.

## 9 Conclusion

This paper uses the oil and natural gas industry to study the impacts of eminent domain on production efficiency and contracting behavior using natural experiments based on state-level variation in regulatory responses. Further, it documents how the change in industry technology coincided with changes to contracting costs, or greater levels of property rights fragmentation.

Increased contracting costs increased the usefulness of eminent domain policies, but are all parties better off when regulators intervene? Within Texas, I find that even though aggregate production increases due to more holes in the ground, the marginal effect of a well drilled with an exception is negative even though these wells are drilled in highly productive oil and natural gas fields. Comparing Texas drilling to New Mexico, I find that the latter produces more oil and natural gas per square mile, which is perhaps attributable to their unitization policy that coordinates drilling on top of force-pooling landowners into participating in the proposed drilling units. Additionally, I present evidence that regions with more regulatory exception wells are, on average, more well-dense with implications for landowners living nearby, some of which have been measured in the literature. Finally, I find that landowners lose contract value when firms have some form of eminent domain at their disposal, given they have engendered enough voluntary cooperation among their neighbors. Fewer landowner concessions in these contracts may lead to worse externalities felt by landowners during the drilling, producing, and plugging phases of well development.[61]

While I cannot provide a welfare estimate, these results suggest that eminent domain policies can be beneficial if the only metric is total production. However, firms are largely increasing output through drilling more holes into the ground, which leads to other costs not quantified in the analysis including capital costs to drill and externality costs to landowners living nearer to more active drilling sites.

[61] These potential costs have been documented in Timmins and Vissing (2017) where they find a negative relationship between landowner concessions and well violations at the census tract level.

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Table 2: Lease Clause and Bundle Summary Statistics

(a) Primary Terms

| | Obs. | Mean | Std. | Min. | Max. |
|---|---|---|---|---|---|
| Royalty | 176,380 | 0.231 | 0.024 | 0.125 | 0.284 |
| Term Length (months) | 284,797 | 42.467 | 11.887 | 12 | 60 |
| Bonus | 5,752 | 15,877.61 | 6,542.64 | 200 | 25,000 |

(b) Auxiliary Clauses

| | Mean | Std. | Clause/Bundle | Mean | Std. |
|---|---|---|---|---|---|
| Disamenity Bundle | 0.085 | (0.158) | Legal Bundle | 0.081 | (0.198) |
| Environment | 0.177 | (0.382) | Vertical Pugh | 0.105 | (0.306) |
| Noise | 0.220 | (0.414) | Pugh | 0.115 | (0.318) |
| Freshwater | 0.016 | (0.124) | Insurance/ Indemnity | 0.040 | (0.197) |
| Surface Casing | 0.005 | (0.068) | Records | 0.078 | (0.268) |
| Compression Station | 0.007 | (0.086) | Attorney Fee | 0.070 | (0.254) |
| Aesthetic Bundle | 0.164 | (0.208) | Water Bundle | 0.020 | (0.072) |
| Fence | 0.370 | (0.483) | Freshwater | 0.016 | (0.124) |
| Setback | 0.134 | (0.34) | Disposal Well | 0.002 | (0.046) |
| Noise | 0.220 | (0.414) | Surface Casing | 0.005 | (0.068) |
| Rest. Residential Street | 0.092 | (0.29) | No Water Use | 0.003 | (0.058) |
| Storage Tank | 0.003 | (0.052) | Groundwater | 0.076 | (0.265) |
| Surface Use Bundle | 0.186 | (0.18) | Bads Bundle | 0.336 | (0.389) |
| No Surface | 0.543 | (0.498) | Subsurface Easement | 0.463 | (0.499) |
| Surface Restriction | 0.031 | (0.174) | No Litigation | 0.210 | (0.407) |
| All Damage | 0.035 | (0.183) | | | |
| Setback | 0.134 | (0.340) | Post-Production Cost | 0.182 | (0.386) |
| Observations | 150,501 | | | | |

(c) Correlation Matrix

| | Royalty | Term (months) | Land Size | Clause |
|---|---|---|---|---|
| Term (months) | -0.2528 | | | |
| Land Size | -0.0138 | -0.1032 | | |
| Clauses | 0.2051 | -0.3790 | -0.0415 | |
| Bonus | 0.5969 | -0.2617 | 0.0818 | 0.5158 |

Notes: (i) The first panel reports the summary statistics for the primary lease terms including royalties, primary term lengths, or the number of months until the lease expires and the mineral rights revert back to the landowner, and bonuses; (ii) the second panel reports the frequency of individual auxiliary clauses that are accounted for in each bundle type; (iii) all bundles except "bads" are clauses protecting landowners and a large term length is interpreted as worse for landowners; (iv) the primary lease quality analysis uses a sub-sample of 150,501 leases with auxiliary clauses; (v) the correlation matrix demonstrates that the pecuniary and non-pecuniary terms of the lease are positively correlated suggesting landowners may not be trading off additional royalty for fewer clause concessions.

Table 3: Absenteeism & Population Characteristics

| | Barnett | Haynesville | Permian |
|---|---|---|---|
| (a) Lease Summary | | | |
| Total Leases | 600,414 | 162,172 | 438,242 |
| Out of State Lessors | 381,703 | 93,144 | 288,559 |
| In State Lessors | 218,711 | 69,028 | 149,683 |
| County Count | 13 | 7 | 52 |
| (b) Fraction Absentee | | | |
| Mean | 0.479 | 0.736 | 0.481 |
| St.Dev. | 0.206 | 0.078 | 0.141 |
| Min | 0.172 | 0.609 | 0.158 |
| Max | 0.762 | 0.832 | 0.786 |
| (c) Population Density | | | |
| Mean | 419,852 | 48,541 | 21,525 |
| St.Dev. | 768,913 | 37,296 | 47,433 |
| Min | 8,490 | 10,546 | 82 |
| Max | 2,368,139 | 121,730 | 278,831 |
| (d) Raw Correlations with Fraction Absentee | | | |
| Pop. Density | -0.737 | -0.744 | 0.082 |
| Median Income | -0.382 | -0.111 | 0.031 |
| Pct. Owner Occupied | -0.583 | -0.563 | -0.039 |

Notes: (i) Summarizes the levels of observed absenteeism among lessors across the three primary regions of oil and gas production used in the analysis; (ii) County Count enumerates the number of counties uses to summarize each region where the Permian is, by far, the largest; (iii) Fraction Absentee summarizes the fraction of leases that are observably signed by individuals not inhabiting the house associated with the property address; (iv) Population Density summarizes the populations across counties in each region where the Barnett has, by far, the greatest density; (v) Raw Correlations reports the correlations between the fraction of absenteeism and Census, populations characteristics across regions where we observe that greater absenteeism is negatively correlated with population density and median income for the Barnett and Haynesville regions; (vi) the data uses 2010 census characteristics in addition to lease observations downloaded from Drillinginfo, and the "absentee lessor" variable construction is described in the text.

Table 4: Aggregate Production (Sq. Mile)

(a) Texas Wells

| | Oil | | Gas | |
|---|---|---|---|---|
| | Mean | St.Dev. | Mean | St.Dev. |
| 3 Mon. Prod. | 6.716 | (1.620) | 10.247 | (1.642) |
| 12 Mon. Prod. | 7.833 | (1.655) | 11.367 | (1.654) |
| 24 Mon. Prod. | 8.256 | (1.682) | 11.782 | (1.682) |
| Cumulative Prod. | 9.018 | (1.880) | 12.478 | (1.789) |
| Horizontal | 0.620 | | 0.675 | |
| Horizontal Len. | 0.087 | | 0.460 | |
| Observations | 152,639 | | 58,217 | |

(b) Texas Population

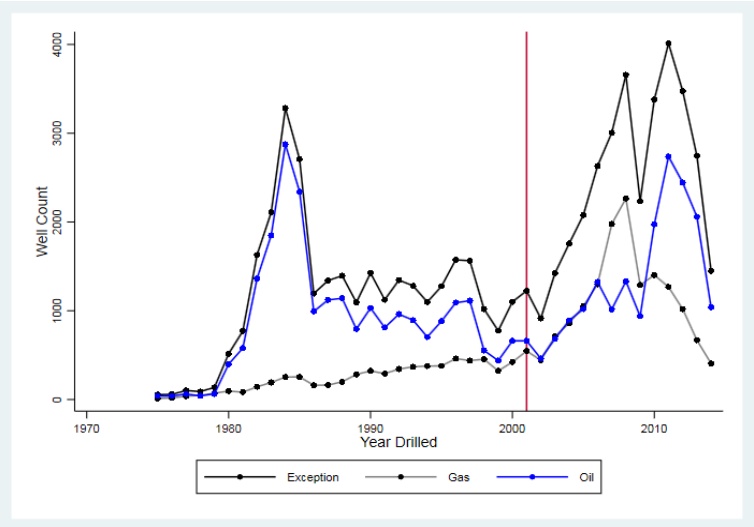
| | Mean | St.Dev. | Min. | Max. |
|---|---|---|---|---|
| Total Household | 3,093.79 | (4,002.496) | 1.00 | 28,372 |
| Pct. Owner Occupied | 71.91 | (19.01) | 0.434 | 100 |
| Population Density | 457.44 | (1060.34) | 0.10 | 6,306.3 |
| Median Inc. | 36,496.66 | (19,936.79) | 7,499 | 139,088 |
| Hispanic Pop. | 15.99 | (16.80) | 28.59 | 100 |
| High School Grad. | 21.79 | (9.338) | 1.411 | 66.667 |
| House Built Before 1936 | 8.018 | (6.941) | 0.069 | 37.185 |

(c) Square Mile Production

| | Mean | St.Dev. | Min. | Max. |
|---|---|---|---|---|
| Oil per Sq. Mile Texas | 9.788 | (2.384) | 16.532 | 38,228 |
| Gas per Sq. Mile Texas | 11.459 | (2.949) | 17.666 | 37,453 |
| Oil Lateral Ct. Texas | 7.193 | (14.421) | 414 | |
| Gas Lateral Ct. Texas | 2.068 | (3.869) | 65 | |
| Oil per Sq. Mile New Mexico | 10.207 | (2.574) | 15.852 | 4,876 |
| Gas per Sq. Mile New Mexico | 12.526 | (2.087) | 17.147 | 5,156 |
| Oil Lateral Ct. New Mexico | 6.211 | (11.154) | 63 | |
| Gas Lateral Ct. New Mexico | 1.665 | (2.456) | 11 | |

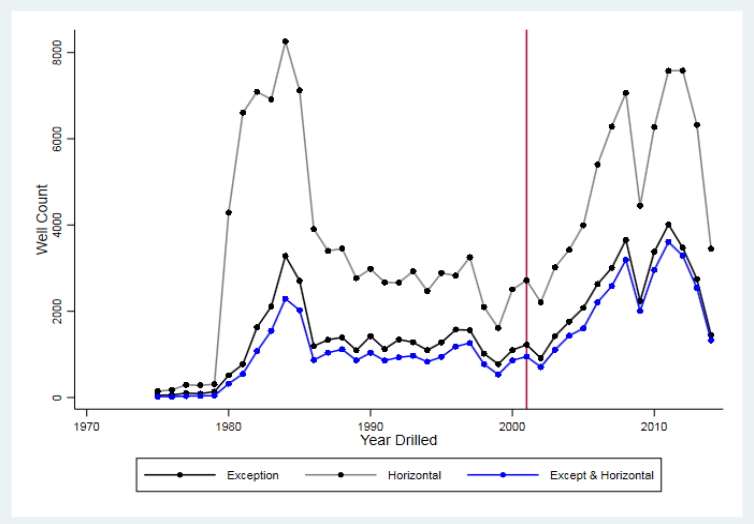
Notes: (i) The first panel summarizes the well-level production values (in logs) for wells located in Texas; (ii) the second panel describes the U.S. Census data description of population characteristics of areas with drilling; (iii) the third panel summarizes the square mile production values for blocks of land located in Texas and New Mexico.

Figure 1: Density & Spacing Exception Frequencies by Well Type



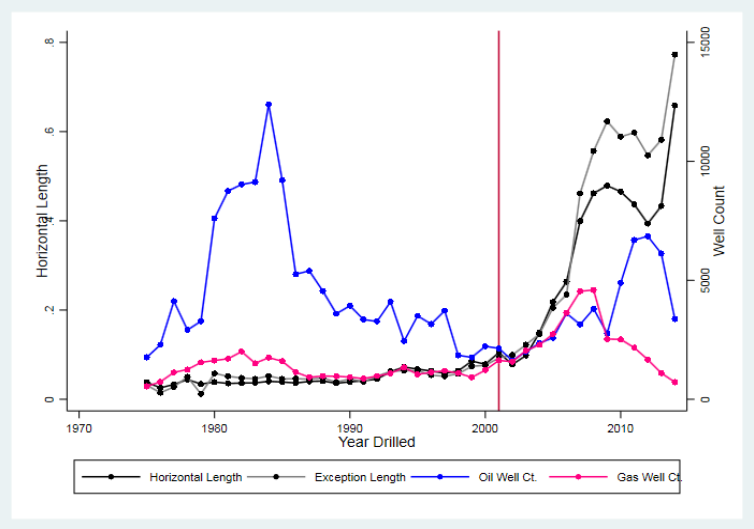

Notes: (i) Documents the increased use of well density and spacing exceptions in Texas; (ii) the gray line describes well exceptions used to drill natural gas wells and the blue describes well exceptions used to drill oil wells; (iii) oil wells were the primary users in the early periods, coinciding with an increase in horizontal laterals documented in Figure 2; (iv) natural gas well use picks up during the shale boom, after the red line drawn to identify 2001, coinciding with drilling in populous regions documented in Figure 4.

Figure 2: Density & Spacing Exceptions Among Horizontal Wells



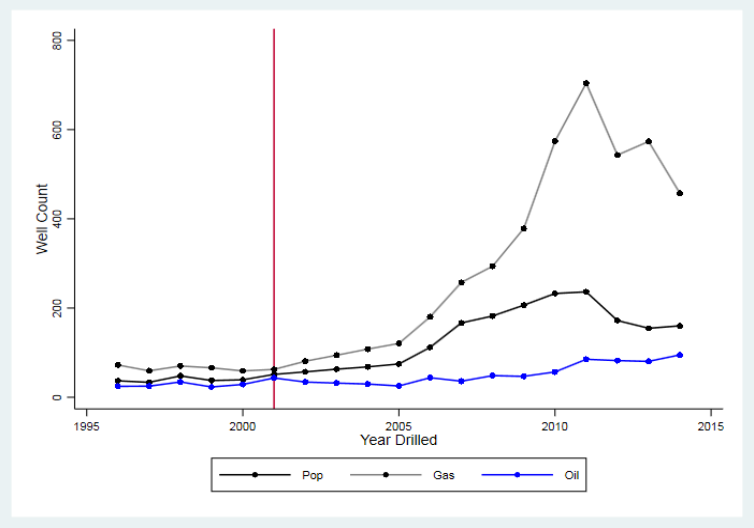

Notes: (i) Documents a relationship between exception wells and horizontal drilling in which the blue line describes the incidence of exceptions granted for horizontal laterals and the black line describes the incidence of exceptions, alone; (ii) the gray line documents the frequency of horizontal laterals which had an early peak for oil wells; however, these wells are significantly smaller in terms of lateral lengths as documented in Figure 3.

Figure 3: Horizontal Lateral Lengths




Notes: (i) Documents a relationship between lateral lengths and well types along with a progression of lateral lengths across time; (ii) the black and gray lines describe the average lateral length among horizontal wells across periods, with a significant peak, especially among exception wells, after the technology change (red line); (iii) these early horizontal wells were largely oil wells as denoted by the blue line.

Figure 4: Population Density of Drilled Regions



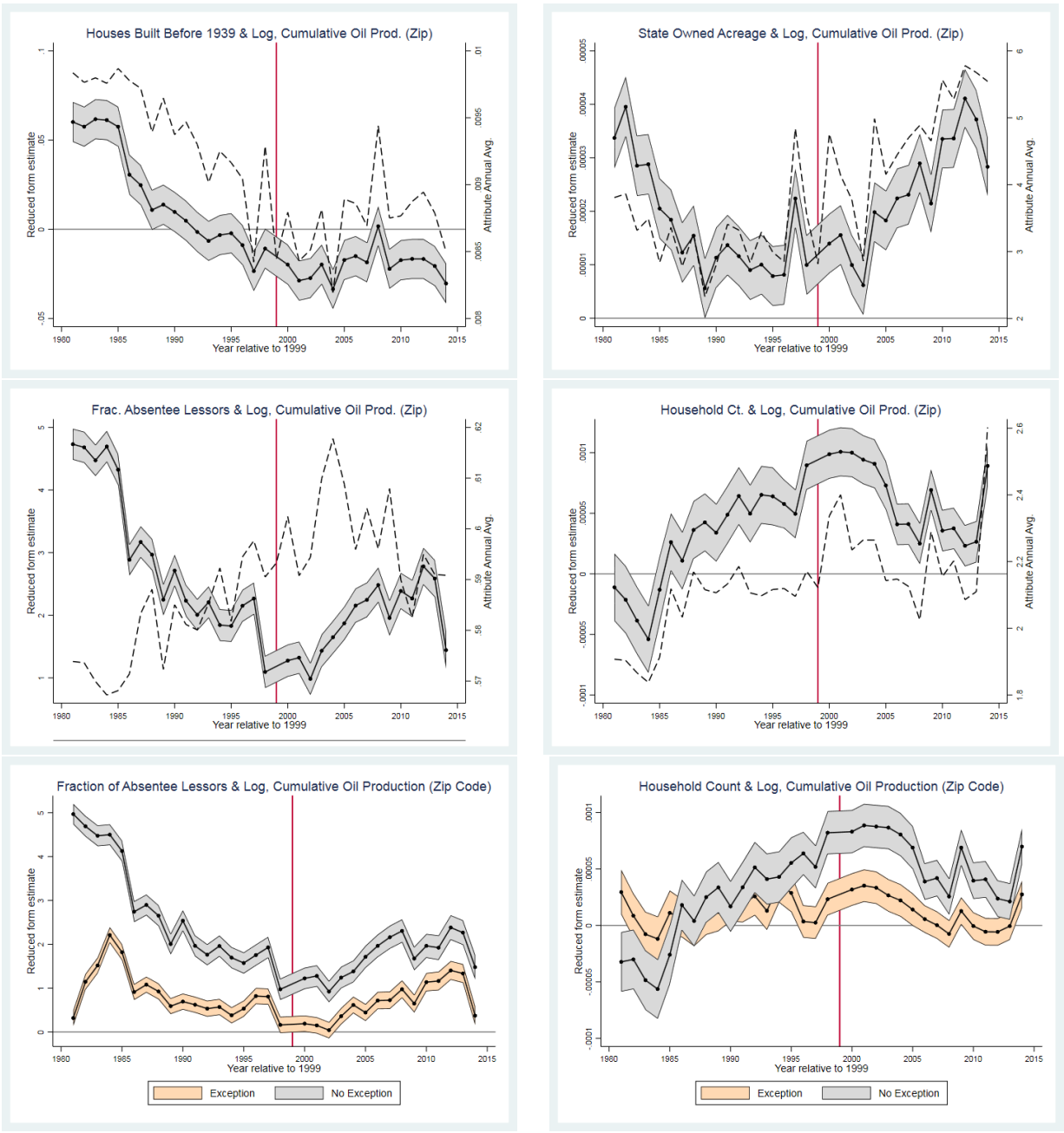

Notes: (i) Documents a relationship between the average population density of regions with drilling across time; (ii) post-technology (red line), gas wells are increasingly drilled in more dense regions while oil wells are largely drilled in similarly dense regions.

Table 5: Trend Analysis: Coefficient Differences

| | 5 yr. | | 2 yr. | | 10 yr. | | 5 yr. buffer | |
|---|---|---|---|---|---|---|---|---|
| Independent Variables | Diff. | Std. | Diff. | Std. | Diff. | Std. | Diff. | Std. |
| (a) Cumulative Oil Production: month, Zip | | | | | | | | |
| Household Count | -0.068 | (0.021) | -0.031 | (0.02) | -0.119 | (0.021) | -0.051 | (0.022) |
| Fraction of Absentee Lessors | 1.739 | (0.258) | 0.745 | (0.256) | 3.004 | (0.264) | 1.266 | (0.266) |
| State Owned Acreage | 0.004 | (0.006) | -0.006 | (0.006) | 0.025 | (0.006) | 0.021 | (0.006) |
| Houses Built Before 1939 | 0.075 | (0.112) | -0.061 | (0.112) | 0.231 | (0.112) | 0.156 | (0.112) |
| (b) Cumulative Gas Production: month, Zip | | | | | | | | |
| Household Count | 0.158 | (0.025) | 0.014 | (0.025) | 0.143 | (0.025) | -0.015 | (0.026) |
| Lessor Count | 0.318 | (0.045) | 0.219 | (0.046) | 0.003 | (0.044) | -0.315 | (0.042) |
| Pct. Hispanic Population | -0.036 | (0.006) | -0.016 | (0.006) | -0.003 | (0.006) | 0.033 | (0.006) |
| Houses Built Before 1939 | -0.07 | (0.014) | -0.024 | (0.014) | 0.011 | (0.014) | 0.081 | (0.014) |

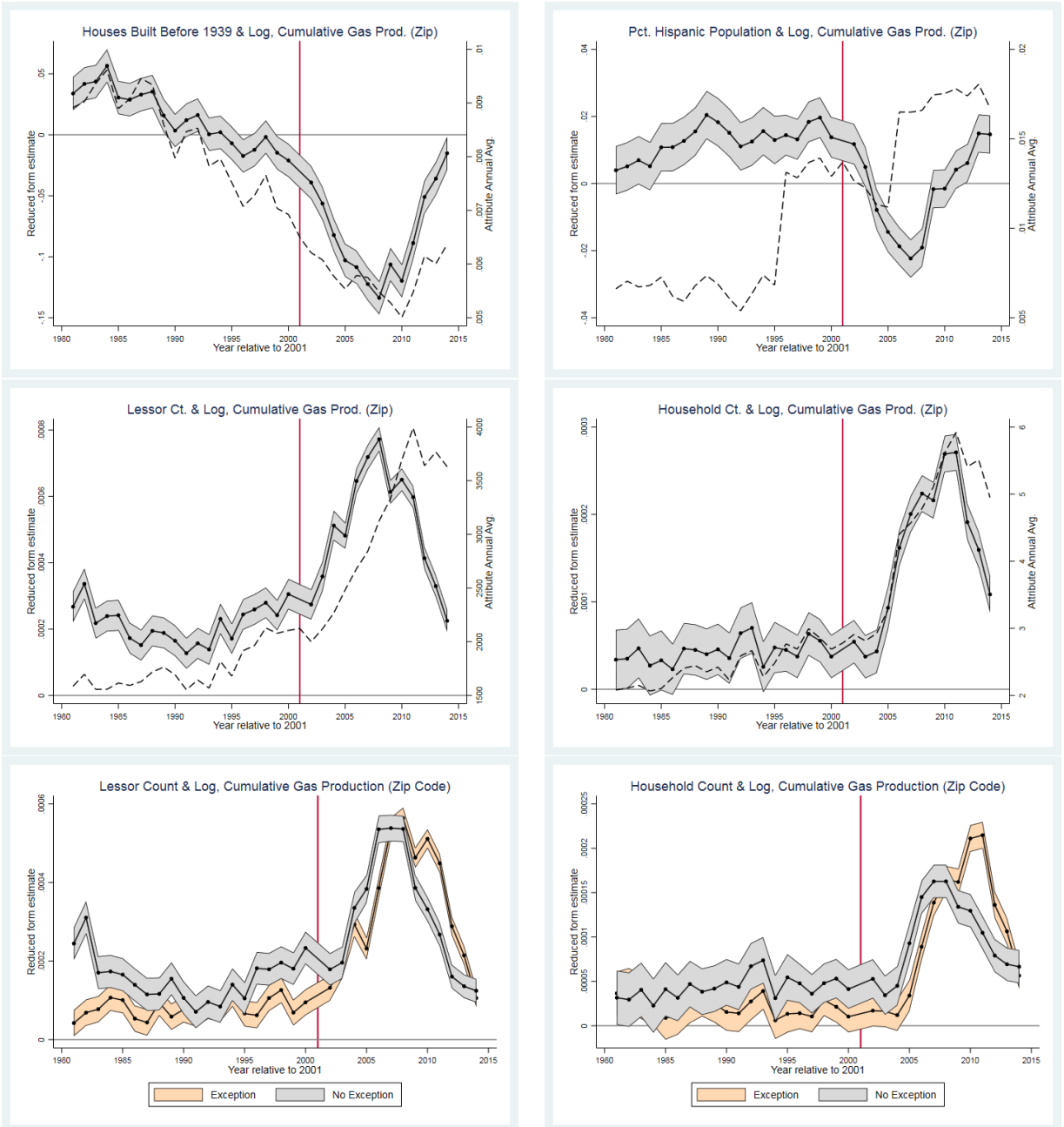
Notes: (i) Each row describes the difference in slope coefficients, plotted in Figures 5 and 6, comparing x years before the technology shift to x years after the technology shift; (ii) *5 yr. buffer* describes the differences in slope coefficients across the five years removed before and after the technology, so for oil wells, it would compare the slopes from years 1989 to 1994 to that of 2004 to 2009; (iii) standards errors of the differences are reported in parentheses.

Figure 5: Oil Production




Notes: (i) Each plot reports year specific coefficients relating different measures of leasing costs to production outcomes before and after technology adoption, occurring between 1999 and 2003; (ii) the dependent variable is the log, sum of oil production among all wells drilled in a month, year period and located in a particular zip code; (iii) the bottom pair plots separate coefficients for wells drilled and not drilled with exceptions; (iv) the dotted lines measure the annual means for each independent variable; (v) more oil wells are drilled in areas with greater levels of lessor *Absenteeism* over time, and *Household Ct.* exhibits a lot of variation post-technology, but population density steeply increases at about 2005 for oil wells.

Figure 6: Gas Production




Notes: (i) Each plot reports year specific coefficients relating different measures of leasing costs to production outcomes before and after technology adoption, occurring between 1999 and 2003; (ii) the dependent variable is the log, sum of natural gas production among all wells drilled in a month, year period and located in a particular zip code; (iii) the bottom pair plots separate coefficients for wells drilled and not drilled with exceptions; (iv) the dotted lines measure the annual means for each independent variable; (v) *Lessor Ct.* and *Household Ct.* are both rapidly increasing after the change in technology.

Table 6: Aggregate Production (Sq. Mile)

| *Dependent Var.: Log, cumulative sum of well production* | | | |
|---|---|---|---|
| | Oil | Gas | Gas, FW |
| | (a) OLS | | |
| *Exception* | 0.107*** | 0.535*** | 0.614*** |
| | (0.004) | (0.011) | (0.016) |
| Constant | 8.632*** | 10.472*** | 9.765*** |
| | (0.024) | (0.025) | (0.058) |
| Observations | 24,651 | 24,651 | 6,121 |
| R-squared | 0.042 | 0.094 | 0.197 |
| | (b) Spatial FE | | |
| *Exception* | 0.088*** | 0.197*** | 0.158*** |
| | (0.003) | (0.013) | (0.015) |
| Constant | 8.678*** | 10.684*** | 10.415*** |
| | (0.014) | (0.016) | (0.034) |
| Observations | 24,651 | 24,651 | 6,121 |
| R-squared | 0.0422 | 0.094 | 0.197 |
| Spatial Groups | 11,392 | 11,392 | 3,251 |

Notes: (i) Each column describes estimates of the effect of wells drilled with well density and spacing exceptions on aggregate oil and natural gas production; (ii) Panel 6a describes the OLS estimates that do not control for space; (iii) Panel 6b describes estimates when controlling for unobserved spatial heterogeneity through two-square mile block fixed effects.

Table 7: Aggregate Production (Sq. Mile): Marginal Well Effects

| *Dependent Var.: Log, cumulative sum of well production* | | | | | | |
|---|---|---|---|---|---|---|
| | Oil | Oil | Gas | Gas | Gas, FW | Gas, FW |
| | | | (a) OLS | | | |
| *Exception* | -0.117*** | 0.001 | -0.013* | -0.244*** | 0.037* | -0.387*** |
| | (0.006) | (0.005) | (0.007) | (0.020) | (0.020) | (0.027) |
| Oil Well Ct. | 0.231*** | 0.218*** | 0.081*** | | -0.049*** | |
| | (0.004) | (0.003) | (0.005) | | (0.014) | |
| Gas Well Ct. | -0.184*** | | 0.542*** | 1.188*** | 0.566*** | 1.480*** |
| | (0.008) | | (0.009) | (0.013) | (0.016) | (0.017) |
| Constant | 8.344*** | 7.523*** | 9.683*** | 8.342*** | 8.838*** | 6.623*** |
| | (0.026) | (0.011) | (0.030) | (0.015) | (0.066) | (0.027) |
| Observations | 24,651 | 88,267 | 24,651 | 88,449 | 6,121 | 31,722 |
| R-squared | 0.250 | 0.115 | 0.186 | 0.157 | 0.342 | 0.278 |
| Year FE | | x | | x | | x |
| | | | (b) Spatial FE | | | |
| *Exception* | -0.066*** | -0.037*** | -0.072*** | -0.254*** | -0.045** | -0.281*** |
| | (0.005) | (0.005) | (0.007) | (0.018) | (0.018) | (0.026) |
| Oil Well Ct. | 0.138*** | 0.152*** | 0.141*** | | 0.175*** | |
| | (0.004) | (0.003) | (0.005) | | (0.013) | |
| Gas Well Ct. | 0.169*** | | 0.309*** | 0.592*** | 0.240*** | 0.594*** |
| | (0.008) | | (0.010) | (0.013) | (0.016) | (0.017) |
| Constant | 8.163*** | 7.703*** | 9.875*** | 8.771*** | 9.637*** | 7.538*** |
| | (0.019) | (0.008) | (0.024) | (0.011) | (0.048) | (0.021) |
| Observations | 24,651 | 88,267 | 24,651 | 88,449 | 6,121 | 31,722 |
| R-squared | 0.100 | 0.112 | 0.134 | 0.153 | 0.209 | 0.273 |
| Spatial Groups | 11,392 | 40,619 | 11,392 | 40,496 | 3,251 | 14,398 |
| Year FE | | x | | x | | x |
| Spatial FE | x | x | x | x | x | x |

Notes: (i) Each column describes estimates of the marginal well effects in addition to the marginal effect of the wells being drilled with well density or spacing exceptions; (ii) Panel 7a describes the OLS estimates that do not control for space; (iii) Panel 7b describes estimates of the marginal effects when controlling for unobserved spatial heterogeneity through two-square mile block fixed effects.

Table 8: Instrumental Variable Model of Exceptions

| Independent Var. | (1) OLS | (2) OLS | (3) 2SLS | (4) 2SLS |
|---|---|---|---|---|
| (a) Cumulative Oil Production: 24 months | | | | |
| *Exception* | 0.227*** | 0.187*** | -1.029*** | -2.526*** |
| | (0.009) | (0.011) | (0.229) | (0.566) |
| Lateral Depth (1e-3) | 0.159*** | 0.149*** | 0.153*** | 0.115*** |
| | (0.002) | (0.003) | (0.002) | (0.008) |
| Horiz. Well | 0.601*** | 0.709*** | 0.831*** | 1.348*** |
| | (0.010) | (0.013) | (0.043) | (0.131) |
| Horizontal Dist. (km) | 0.302*** | 0.345*** | 0.439*** | 0.669*** |
| | (0.020) | (0.020) | (0.032) | (0.074) |
| Observations | 147,328 | 83,193 | 144,602 | 78,732 |
| R-squared | 0.105 | 0.124 | | |
| Year Samp. | | 1990 | | 1990 |
| Spatial Groups | 139 | 133 | 139 | 133 |
| Wu-Hausman Z-score | | | 3.51 | 4.34 |
| (b) Cumulative Gas Production: 24 months | | | | |
| *Exception* | 0.090*** | 0.077*** | -0.742* | -0.977*** |
| | (0.012) | (0.012) | (0.379) | (0.375) |
| Lateral Depth (1e-3) | 0.182*** | 0.179*** | 0.184*** | 0.174*** |
| | (0.004) | (0.004) | (0.005) | (0.005) |
| Horiz. Well | 0.174*** | 0.166*** | 0.185*** | 0.189*** |
| | (0.014) | (0.014) | (0.015) | (0.017) |
| Horizontal Dist. (km) | 0.532*** | 0.535*** | 0.643*** | 0.688*** |
| | (0.019) | (0.019) | (0.054) | (0.056) |
| Observations | 47,566 | 43,741 | 47,566 | 42,831 |
| R-squared | 0.154 | 0.162 | | |
| Year Samp. | | 1990 | | 1990 |
| Spatial Groups | 123 | 121 | 123 | 121 |
| Wu-Hausman Z-score | | | -19.15 | 7.03 |
| Year FE | x | x | x | x |
| Coordinates | x | x | x | x |
| Spatial FE | x | x | x | x |

Notes: (i) Each column describes estimates from different models including the OLS specifications in columns (1) and (2) and 2SLS in (3) and (4); (ii) Panel 8a reports estimates in which the dependent variables is the cumulative sum of oil production during the first 24 months and Panel 8b reports estimates for the cumulative sum of gas production during the first 24 months; (iii) columns (1) and (3) report results using the full data sample and columns (2) and (4) are estimated with wells drilled after 1990; (iv) each model is estimated controlling for first year of production fixed effects, flexible time trends, and spatial fixed effects controlling for whether the well is located in a tight shale basin and 20-mile blocks through estimated spatial fixed effects.

Table 9: First Stage & Reduced Form Models of Exceptions

| | First Stage | | Reduced Form | |
|---|---|---|---|---|
| Independent Var. | *Exception* | *Exception* | Cum. Prod. | Cum. Prod. |
| | (a) Oil Wells | | | |
| Frac. Absentee Lessors (zip) | 0.212*** | 0.146*** | -0.218*** | -0.365*** |
| | (0.014) | (0.020) | (0.046) | (0.061) |
| Lateral Depth (1e-3) | -0.004*** | -0.012*** | 0.156*** | 0.145*** |
| | (0.001) | (0.001) | (0.002) | (0.003) |
| Horiz. Well | 0.180*** | 0.229*** | 0.647*** | 0.772*** |
| | (0.003) | (0.004) | (0.010) | (0.014) |
| Horizontal Dist. (km) | 0.110*** | 0.123*** | 0.327*** | 0.362*** |
| | (0.006) | (0.006) | (0.020) | (0.020) |
| Observations | 145,235 | 79,132 | 144,602 | 78,732 |
| R-squared | 0.061 | 0.057 | 0.102 | 0.124 |
| Fstat | 201.90 | 132.42 | | |
| Spatial Groups | 139 | 132 | 139 | 132 |
| | (b) Gas Wells | | | |
| Pct. Owner Occupied (zip) | -1.667*** | -1.759*** | 1.242** | 1.728*** |
| | (0.237) | (0.250) | (0.603) | (0.609) |
| Lateral Depth (1e-3) | 0.001 | -0.001 | 0.182*** | 0.174*** |
| | (0.002) | (0.002) | (0.004) | (0.004) |
| Horiz. Well | 0.011** | 0.014** | 0.176*** | 0.174*** |
| | (0.005) | (0.006) | (0.014) | (0.014) |
| Horizontal Dist. (km) | 0.134*** | 0.138*** | 0.544*** | 0.553*** |
| | (0.007) | (0.008) | (0.019) | (0.019) |
| Observations | 47,699 | 42,961 | 47,566 | 42,831 |
| R-squared | 0.065 | 0.051 | 0.153 | 0.162 |
| Fstat | 53.073 | 55.51 | . | |
| Spatial Groups | 123 | 121 | 123 | 121 |
| Year Samp. | | 1990 | | 1990 |
| Year FE | x | x | x | x |
| Coordinates | x | x | x | x |
| Spatial FE | | x | | x |

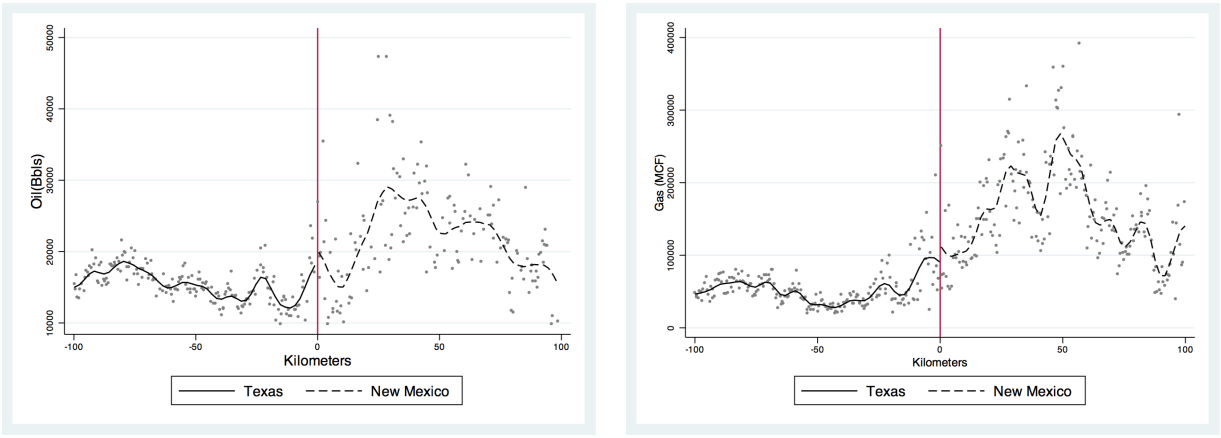
Notes: (i) The first two columns describe first stage estimates and the last two columns describe the reduced form estimates; (ii) Panel 9a reports estimates for robust and fixed effect specifications among oil wells and Panel 9b reports estimates among gas wells; (iii) columns (1) and (3) report results using the full data sample and columns (2) and (4) are estimated with wells drilled after 1990; (iv) each model is estimated controlling for first year of production fixed effects and spatial fixed effects controlling for whether the well is located in a tight shale basin; (v) *Total Depth* is within the spatial and temporal resolution, -0.300 (0.825) measures the insignificant relationship between *Pct. Owner Occupied (zip)* and *Lateral Depth* among gas wells and 0.137 (0.101) between *Frac. Absentee Lessors (zip)* and *Lateral Depth*.

Table 10: Different Samples of the Data

| Independent Var. | Full | Before 1990 | After 1990 | After 2000 | After 2005 |
|---|---|---|---|---|---|
| | | | (a) Oil Wells | | |
| *Exception* | -1.029*** | -0.707*** | -2.526*** | -1.161** | 0.442 |
| | (0.229) | (0.249) | (0.566) | (0.464) | (0.406) |
| Lateral Depth (1e-3) | 0.153*** | 0.164*** | 0.115*** | 0.117*** | 0.154*** |
| | (0.002) | (0.003) | (0.008) | (0.009) | (0.009) |
| Horiz. Well | 0.831*** | 0.782*** | 1.348*** | 0.861*** | 0.426*** |
| | (0.043) | (0.043) | (0.131) | (0.109) | (0.085) |
| Horizontal Dist. (km) | 0.439*** | 0.127 | 0.669*** | 0.558*** | 0.332*** |
| | (0.032) | (0.083) | (0.074) | (0.064) | (0.053) |
| Observations | 144,602 | 91,751 | 78,732 | 50,680 | 40,226 |
| Number of Groups | 139 | 137 | 132 | 126 | 121 |
| | | | (b) Gas Wells | | |
| *Exception* | -0.742* | 0.113 | -0.977*** | -1.230*** | -0.960** |
| | (0.379) | (0.880) | (0.375) | (0.423) | (0.440) |
| Lateral Depth (1e-3) | 0.184*** | 0.207*** | 0.174*** | 0.155*** | 0.121*** |
| | (0.005) | (0.011) | (0.005) | (0.006) | (0.007) |
| Horiz. Well | 0.185*** | 0.147*** | 0.189*** | 0.217*** | 0.290*** |
| | (0.015) | (0.025) | (0.017) | (0.020) | (0.025) |
| Horizontal Dist. (km) | 0.643*** | 0.670*** | 0.688*** | 0.733*** | 0.740*** |
| | (0.054) | (0.114) | (0.056) | (0.061) | (0.062) |
| Observations | 47,566 | 14,162 | 42,831 | 32,226 | 22,223 |
| Number of Groups | 123 | 107 | 121 | 116 | 110 |
| Year FE | x | x | x | x | x |
| Coordinates | x | x | x | x | x |
| Spatial FE | x | x | x | x | x |

Notes: (i) Each column describes estimates from different IV models restricting the sample by years of first production; (ii) Panel 10a reports the IV estimates for fixed effect specifications among oil wells and Panel 10b reports estimates among gas wells; (iii) all models are estimated with spatial-level fixed effects controlling for unobserved spatial heterogeneity, controlling for first year of production fixed effects, and spatial fixed effects controlling for whether the well is located in a tight shale basin; (iv) restricting data to wells drilled after 2005 isolates drilling activity after technological innovations combining large scale hydraulic fracturing with longer horizontal laterals.

Figure 7: Border Discontinuity: Visual Evidence




(a) Permian: Average Oil (Bbls) per Kilometer

(b) Permian: Average Gas (MCF) per Kilometer

Table 11: Aggregate Exceptions: Zip Code Characteristics

| | Mean (Stdev) | | Mean (Stdev) | | T-Test |
|---|---|---|---|---|---|
| | Texas | | New Mexico | | |
| HS Grad | 26.98 | (13.04) | 23.81 | (7.99) | 1.90 |
| Hispanic Pop. | 37.8 | (15.59) | 34.49 | (16.05) | 1.22 |
| Pop. Density | 105.58 | (272.32) | 39.58 | (113.72) | 1.82 |
| Pct. Owner Occupied | 73.26 | (12.47) | 69.32 | (21.27) | 1.22 |
| Median HH Inc. | 35,030.98 | (15,777.75) | 32,667.58 | (14,697.1) | 0.93 |
| Total HH | 2,554.08 | (3,432.06) | 2,866.38 | (4,388.84) | -0.45 |

Table 12: Border Discontinuity (Sq. Mile)

*Dependent Var.: Log, cumulative sum of well production*

(a) OLS

| | North/South Oil | North/South Oil | East/West Oil | East/West Oil |
|---|---|---|---|---|
| NewMexico | 0.813*** | 0.991*** | 1.289*** | 1.105*** |
| | (0.313) | (0.311) | (0.227) | (0.216) |
| Constant | 10.012*** | 9.835*** | 9.297*** | 9.481*** |
| | (0.212) | (0.211) | (0.154) | (0.147) |
| Observations | 7,840 | 7,840 | 9,721 | 9,721 |
| R-squared | 0.026 | 0.039 | 0.015 | 0.111 |
| | Gas | Gas | Gas | Gas |
| NewMexico | 0.312 | 0.084 | 2.041*** | 0.876*** |
| | (0.306) | (0.192) | (0.346) | (0.189) |
| Constant | 11.559*** | 9.374*** | 9.025*** | 8.679*** |
| | (0.207) | (0.158) | (0.235) | (0.146) |
| Observations | 7,840 | 26,314 | 9,721 | 38,540 |
| R-squared | 0.076 | 0.063 | 0.072 | 0.094 |
| Year FE | | x | | x |

(b) Spatial FE

| | Oil | Oil | Oil | Oil |
|---|---|---|---|---|
| NewMexico | 0.854*** | 0.819*** | 1.201*** | 0.808*** |
| | (0.282) | (0.171) | (0.224) | (0.134) |
| Constant | 9.710*** | 8.771*** | 9.260*** | 9.209*** |
| | (0.193) | (0.141) | (0.155) | (0.104) |
| Observations | 7,840 | 26,314 | 9,721 | 38,540 |
| R-squared | 0.063 | 0.110 | 0.017 | 0.059 |
| | Gas | Gas | Gas | Gas |
| NewMexico | 0.538* | 0.136 | 1.818*** | 0.660*** |
| | (0.307) | (0.194) | (0.327) | (0.185) |
| Constant | 11.749*** | 9.542*** | 8.760*** | 8.702*** |
| | (0.211) | (0.161) | (0.226) | (0.144) |
| Observations | 7,840 | 26,314 | 9,721 | 38,540 |
| R-squared | 0.074 | 0.065 | 0.073 | 0.067 |
| Year FE | | x | | x |
| Spatial FE | x | x | x | x |

Notes: (i) Each column and panel describe estimates from different aggregate production models; (ii) Panel 12a reports the estimates for OLS, Texas/New Mexico border comparing the square mile blocks of aggregate production located within 100 km of the state border, controlling for year of first production and not; (iii) all models in Panel 12b are estimated with spatial-level fixed effects controlling for unobserved spatial heterogeneity; (iv) spatial fixed effects are estimated for 2 square mile blocks; (v) estimates are consistent with 2 and 5 sq. mile spatial resolutions, though these estimates are not reported; (vi) year specifications regress the first 24 months of production for all wells drilled in the square mile region during a particular year and independent variables include first year of production fixed effects.

Table 13: Exception Costs (Sq. Mile)

| | Gas | Oil | Wellpad | Firm |
|---|---|---|---|---|
| | (a) Exception Wells in Texas | | | |
| *Exception* | 0.0974*** | 1.029*** | 0.484*** | 0.0245*** |
| | (0.00296) | (0.00750) | (0.00798) | (0.00179) |
| Constant | 1.114*** | 2.766*** | 3.129*** | 1.888*** |
| | (0.0134) | (0.0341) | (0.0356) | (0.00812) |
| Observations | 27,859 | 27,859 | 15,190 | 27,859 |
| R-squared | 0.028 | 0.6328 | 0.359 | 0.0379 |
| | (b) Texas & New Mexico Border | | | |
| New Mexico | 1.033*** | -1.578*** | -1.084*** | 0.637*** |
| | (0.030) | (0.212) | (0.135) | (0.026) |
| Constant | 0.464*** | 7.938*** | 4.627*** | 1.939*** |
| | (0.016) | (0.117) | (0.069) | (0.014) |
| Observations | 15,732 | 15,732 | 8,450 | 15,732 |
| R-squared | 0.072 | 0.004 | 0.008 | 0.037 |

Notes: (i) Each column describes estimates from different models that describe a relationship between a density or competition measures and exceptions; (ii) each model is estimated with two square mile square block fixed effects to control for unobserved, spatial heterogeneity; (iii) the first three columns describe positive relationships between exception wells and well density, either oil or gas wells or wellpads; (iv) the last column reports the relationship between exceptions and greater competition measured through the firm count.

Table 14: Costs (Sq. Mile): Controlling for Year of First Production

(a) Exception Wells in Texas

| | Gas | Oil | Wellpad | Firm | Horz. Length | Horz. Frac. | Min. Dist. |
|---|---|---|---|---|---|---|---|
| *Exception* | 0.00442*** | 0.0530*** | 0.0152*** | 0.00253*** | 0.000376*** | 0.000618*** | -0.000619 |
| | (0.000324) | (0.00126) | (0.000758) | (0.000249) | (0.000109) | (0.000161) | (0.000688) |
| Constant | -0.0473 | 0.359 | 2.185*** | 1.093*** | 0.0339 | 0.711 | 0.308 |
| | (8,414) | (1.504) | (0.817) | (0.296) | (0.130) | (2,047) | (8,784) |
| Observations | 171,842 | 171,842 | 141,259 | 171,842 | 171,842 | 171,842 | 170,622 |
| R-squared | 0.023 | 0.089 | 0.037 | 0.043 | 0.146 | 0.325 | 0.052 |
| Spatial Groups | 14,679 | 14,679 | 11,719 | 14,679 | 14,679 | 14,679 | 14,636 |
| Spatial FE | x | x | x | x | x | x | x |
| Year FE | x | x | x | x | x | x | x |

(b) Texas & New Mexico Border

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| NewMexico | -0.021** | -0.000 | 0.010 | 0.003 | 0.057*** | 0.557*** | -0.546*** |
| | (0.008) | (0.043) | (0.030) | (0.008) | (0.004) | (0.006) | (0.029) |
| Constant | 0.036*** | 1.887*** | 1.273 | 1.026** | -0.188 | -0.268 | 0.429 |
| | (0.011) | (0.060) | (1.384) | (0.459) | (0.257) | (0.352) | (1.642) |
| Observations | 60,687 | 60,687 | 43,895 | 60,687 | 60,687 | 60,687 | 60,525 |
| R-squared | 0.027 | 0.019 | 0.029 | 0.083 | 0.156 | 0.156 | 0.054 |
| Spatial Groups | 419 | 419 | 375 | 419 | 419 | 419 | 418 |
| Spatial FE | x | x | x | x | x | x | x |
| Year FE | x | x | x | x | x | x | x |

Notes: (i) Each column describes estimates from different models that describe a relationship between a density or competition measures and exceptions; (ii) each model is estimated with two square mile square block fixed effects to control for unobserved, spatial heterogeneity; (iii) the first three columns describe positive relationships between exception wells and well density, either oil or gas wells or wellpads; (iv) the last column reports the relationship between exceptions and greater competition measured through the firm count.

Table 15: Individual Holdups with Uncertain "Eminent Domain"

| | Royalty | Vert. Pugh | Legal | Post. Prod. Cost | Noise | Environ. |
|---|---|---|---|---|---|---|
| Rule37 | 0.002** | -0.052*** | -0.037*** | -0.084*** | -0.070*** | -0.053* |
| | (0.001) | (0.017) | (0.013) | (0.022) | (0.026) | (0.032) |
| HHI | -0.011*** | -0.136*** | 0.067 | -0.165*** | -0.247*** | -0.284*** |
| | (0.003) | (0.043) | (0.045) | (0.047) | (0.083) | (0.074) |
| Land size | 0.001*** | -0.003* | 0.001 | 0.000 | -0.004 | 0.001 |
| | (0.000) | (0.001) | (0.001) | (0.002) | (0.003) | (0.002) |
| Near wellpad | 0.000 | -0.002 | -0.000 | 0.000 | -0.000 | -0.001 |
| | (0.000) | (0.002) | (0.001) | (0.002) | (0.003) | (0.003) |
| Constant | 0.168*** | 0.159*** | -0.072 | 0.710*** | 0.247*** | 0.269*** |
| | (0.012) | (0.046) | (0.046) | (0.075) | (0.085) | (0.077) |
| Observations | 169,823 | 125,279 | 125,279 | 125,279 | 72,906 | 72,906 |
| R-squared | 0.401 | 0.278 | 0.196 | 0.311 | 0.265 | 0.326 |
| Period, Firm FE | x | x | x | x | x | x |
| Std. Err. Wellpad Cluster | x | x | x | x | x | x |

Notes: (i) Each column represents a separate regression of lease quality on measures of market structure, a dummy indicating the lease was signed in the same month the Rule 37 exception was filed with the Texas Railroad Commission, and other observable parcel characteristics; (ii) the standard errors are clustered at the wellpad level to capture any correlation within across wells drilled near to one another.