Creating Anticommons:

Historical Land Privatization and Modern Natural Resource Use[1]

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May 31, 2017

Abstract: We explain how privatizing the commons to promote use of one land-based resource (agriculture) discourages use of another (shale oil). We test for this 'anticommons' problem using a natural experiment on the Bakken, one of the world's largest shale reserves. Before oil discovery, U.S. land policies inadvertently created a mosaic of private and tribal subsurface ownership on the Fort Berthold Indian Reservation. We compare horizontal drilling across parcels during the 2005-2015 fracking boom and find that fragmented ownership significantly reduced royalty income, relative to contiguous tribal ownership. This evidence highlights a cost of subdividing land containing spatially expansive natural resources.

Key words: anticommons, oil, indigenous policy, transaction costs, resource booms, privatization

JEL Codes: O13, Q32, Q33, D23, H82, K11

[1] For helpful comments, we thank Alex Rothenberg, Jane Friesen, Dean Lueck, Donna Feir, Gary Libecap, Terry Anderson, Shawn Regan, Tim Fitzgerald, Dan Benjamin, Ronald Trosper, and seminar participants at Simon Fraser U., Stanford U. (Hoover Economic Policy Talk), U. of Illinois, U. of Hawaii, UC-Riverside, and the Property and Environment Research Center. We also thank attendees of conference sessions hosted by SOIE, UC Santa Barbara, WEAI, AERE, and the Midwest International Development Conference. We are grateful to Matt Kelly, an attorney of Tarlow and Stonecipher PLLC for helpful discussions about oil and gas leasing on the Bakken.

I. Introduction

Much of the world's indigenous populations live on communally owned land and this ownership structure has likely hindered development. The main problem is that, under communal ownership, individuals have weak incentives to invest in land improvements because they cannot exclude other group members from the returns (see Demsetz 1967, Alchian and Demsetz 1973, Feder and Feeny 1991, Besley 1995, Barzel 1997, Goldstein and Udry 2008, Besley and Ghatak 2010). Recognition of this problem has motivated a practical solution: create strong individual exclusion rights through privatization and land titling (see Alston et al. 1996). Such programs have codified parcel ownership in the United States, South America, Asia, and Africa, and are being debated for indigenous populations in Canada (Flanagan et al. 2010, Aragón and Kessler 2017). Where applied, the programs have generally stimulated parcel-specific investments as theory predicts.[2]

We consider a potential unintended consequence. Subdividing land beneficially encloses the commons for some valuable land uses (e.g., agriculture) but can create anticommons problems for other valuable uses. Anticommons problems arise when multiple individuals hold exclusion rights to a resource that can be used only with consent of each owner (Heller 1998, Buchanan and Yoon 2000, Heller 2008). Our concern is that subdivision into small parcels may stunt potential income from resource uses requiring management at larger spatial scales (e.g., wind farming, shale oil and gas extraction, wildlife conservation, water irrigation, and forestry). This is especially important when potential income from large-scale resources is high, when the ability to earn income from them is time-sensitive, and when privatization is incomplete as we explain below.

We study this issue by examining the legacy of the U.S. government's sweeping program for "allotting" Native American land over 1887-1934 (see Trosper 1978, Anderson and Lueck 1992, Anderson 1995, Akee 2009). Roughly 41 million acres of communal Indian land was subdivided primarily into 160, 80, and 40 acre parcels for individual Native American families with the goal of encouraging productive farming (Carlson 1981).[3] Subsurface resources were also privatized, often inadvertently and incompletely, and we hypothesize that the resulting fragmented ownership structure helps to explain why an estimated $1.5 trillion in coal, oil and other energy reserves remain untapped beneath Native

[2] Galiani and Schargrodsky (2012) review empirical studies on privatization. Most recent studies find that private ownership has stimulated productivity-enhancing investments in land and agriculture (see Banerjee et al. 2002, Field 2005, Do and Iyer 2008, Galiani and Schargrodsky 2010).

[3] A less charitable interpretation is that land allotment policies were devised to transfer land from Native Americans to white settlers (Carlson 1981, Banner 2005).

American lands (U.S. Senate 2009). Oklahoma's Osage Indian reservation—the one major example of a reservation whose surface was fully privatized but whose communal tribal mineral estate was left fully intact —has successfully managed oil as a substantial source of tribal income since the early 1900s (Ambler 1990). This anecdote highlights the potential benefits of tribal mineral ownership, but one cannot rule out other explanations for the relative success (e.g., better oil endowments, different culture, etc.).[4]

We exploit a natural experiment in subsurface ownership that holds non-ownership factors constant. We study modern oil drilling through the Bakken shale in North Dakota, which sits beneath the Fort Berthold Indian reservation. The reservation was almost fully allotted over 1887-1934, but contiguous tribal ownership was restored on part of the reservation through a federal water reclamation project in 1947. The upshot is that shale ownership now occurs in three categories: tribal, privatized parcels (fee simple), and allotted trust parcels for which multiple heirs of the original allottee hold exclusion rights as described in section 4. Importantly, ownership was established before the discovery of oil and is exogenous to shale quality. This exogeneity is rare in studies of property rights and resource use, because rights in most settings are determined by resource quality (Besley 1995, Kaffine 2009, Galiani and Schargrodsky 2012).[5] Because of the exogeneity, we are able to credibly estimate the causal effects of ownership on drilling patterns during the fracking boom of 2005-2015.[6]

Moreover, the comparative assessment of shale development enables novel tests of anticommons theory for two reasons.[7] First, modern technology of oil extraction –horizontal fracking – is executed by drilling a horizontal line, or "lateral," that extends about two miles from a vertical well pad. Profitable oil units are typically 1280 acres, configured in skinny, rectangular areas. Exploiting this technology in a fragmented landscape can generate large land assembly transaction costs of finding mineral owners and obtaining their consent. Although this spatial coordination challenge can arise wherever parcels are small, the

[4] The surface area of the Osage reservation was fully privatized into fee simple parcels; evidence suggests this land tenure arrangement generates the most agricultural investment, as standard models of property rights predict (Anderson and Lueck 1992).

[5] Indeed, studies of the effects of tenure on surface investments are confounded by possible selection bias because tenure is not exogenous to surface land characteristics (see Akee 2009, Akee and Jorgensen 2014).

[6] In the longer run, new property rights to shale might endogenously emerge as its high economic value is recognized. This point about the evolution of property rights is discussed in a more general context by Demsetz (1967) and Copeland and Taylor (2009). In the time span of our study, which is a short run oil boom, patterns of parcel ownership on the reservation were predetermined by historical events as explained in section 4.

[7] Heller (2012) notes that most research on anticommons is theoretical, rather than empirical. This may be because anticommons problems are more difficult to code when compared to common property problems. In the latter case, a resource becomes visibly ruined, wasted, or congested, but with anticommons, the predicted outcome of underutilization is difficult to observe.

challenge is exacerbated on Indian reservations where there are also multiple owners of individual parcels due to heirship.[8] The challenge is plausibly less severe for projects that would extract oil from beneath contiguous swaths of tribally owned lands because rights to exclude an economically feasible drilling project are consolidated.

Second, the spatial nature of horizontal drilling allows us to study how the economic use of a natural resource by one owner is affected by the property rights governing neighboring parcels. When exploitation requires consent across parcels, even those parcels with clear rights may not be able to utilize the resource due to the tenure, size, or shape of neighboring parcels. The cross-parcel development of horizontal wells in the tenure mosaic of Indian reservations provides a rich setting for identifying parcel-level spillover effects. In this way our study relates to Aragón (2015) who finds that property rights in one area can have local economic spillovers in the context of Canadian aboriginal lands.

To motivate the empirical tests, we model the "anticommons" as a transaction cost and coordination failure problem, building from Buchanan and Yoon (2000). These problems increase with *N*, the number of exclusion rights spanning the spatial scale of an economically feasible drilling project. The probability of a profitable project declines with *N*, along with expected rent from the shale, regardless of whether coordination failure or transaction costs are the driving mechanism.

We test the theoretical framework by comparing patterns of horizontal drilling across over 40,000 parcels off and on the reservation during the 2005-2015 boom. We find the probability a parcel was penetrated by a horizontal well – which generally means the owner was compensated for her shale - is strongly affected by parcel size and shape. Larger and more rectangular parcels were more likely to be exploited than smaller squares. These findings complement studies that detail how the "wrong" parcel allocation (at least for one type of resource use) can impair current productive use because parcels and resource use are path dependent (Libecap and Lueck 2011, Bleakley and Ferrie 2014, Brooks and Lutz 2016, Hornbeck and Keniston 2017).

We also find large effects of neighborhood subdivision on the probability a parcel has been drilled. Holding constant a given parcel's size and shape, adding more private neighbors within a one-mile radius significantly decreases the probability the parcel's shale has been exploited. The negative effect is twice as large for land that was subdivided into allotted trust

[8] In Heller's (1998) terminology, there are 'legal anticommons' on even large heirship parcels that fully contain a horizontal well because of multiple owners. Most heirship parcels are small, however, implying the spatial anticommons problems are combined with legal anticommons. This is one distinction between anticommons and land assembly problems studied by economists (see Brooks and Lutz 2016 and Isaac et. al 2016).

tenure (i.e. heirship lands) when compared to fee simple, but both effects are large. In contrast, we do not find a negative effect for neighboring tribal parcels, which share a common owner and hence do not require spatial coordination amongst additional owners. These findings support qualitative assessments by local experts, such as Ogden (2011), who asserts that because of a "highly fractionated land base it is almost impossible for companies to gather the approval of all the landowners of any given tract."

In a policy thought-experiment, we estimate the effects of a pre-2005 transfer of all mineral ownership on the reservation to tribal ownership. The transfer would have increased the probability that a parcel's shale was exploited during the boom by roughly 33 percent. However, we also find evidence that wells penetrating private parcels earned higher revenue and delivered higher royalty payments as the anticommons theory predicts. Accounting for the lower compensation earned by tribal projects, we still estimate that transferring ownership to the tribe would have resulted in at least a 16 percent increase in expected rent from the boom. For context, the average per-parcel royalty payment from a Bakken well was about $87,314 during the first 18 months after well completion. Hence, conversion to tribal ownership would increase expected compensation within the first 18 months by roughly $14,344. This is a per-capita increase of $19,483, based on the 2010 Ft. Berthold population, which exceeds the reservation's 2010 per capita income of $13,543.

These large estimates underscore the importance of institutional arrangements that facilitate resource development and are in line with Banerjee and Iyer (2005), who also find adverse effects from the legacy of colonial land tenure systems. Our results are qualitatively consistent with Feyrer et al. (2017), who find large beneficial effects of oil royalty payments on local economies. The potential drawback is that fracking may cause local environmental harms (see, e.g., Olmstead et al. 2013, Muehlenbachs et al. 2015) suggesting the benefits of more aggressive drilling may be overstated (Bartik et al. 2016). We recognize this issue but point out that, on Fort Berthold and elsewhere, residents were exposed to drilling disamenities (e.g., noise, pollution, crime, congestion) whether or not compensated for shale. The worst scenario, it seems, is to face institutional constraints on compensation while still being exposed to the disamenities of a resource boom.

II. Background Literature: Exclusion, Commons, and Anticommons

In the United States and other countries, ownership of natural resources follows the boundaries of surface ownership. This regime creates a fundamental tension in the design of property rights over landscapes containing resources that are optimally managed at spatial

scales larger than surface boundaries such as oil reservoirs, shale oil, groundwater, wind, coal, and wildlife (Lueck 1989, Fennel 2011, Bradshaw and Lueck 2015). We articulate this tension in the context of the commons and anticommons literature, in order to broadly motivate the specific empirical issues we study.

A. Subdivision and Enclosure of the Commons

The "commons" is often conceptualized as an agricultural landscape on which a group of *N* individuals have use rights. The group can exclude outsiders, but each individual lacks the right (or ability) to exclude other members.[9] The inability to exclude leads to overuse of a fixed, congestible resource such as grazing land because each user bears only *1/N* of the long-run costs of his current use but accrues the full current benefit. Similarly, the inability to exclude can result in under-investment in crops for which there is a time lag between labor investments and output flow. The incentive problem is that the individual investor bears the full current cost but expects to accrue only *1/N* of the returns in later periods.

Two solutions to these problems involve privatizating the landscape. The first is to grant ownership to one individual by vesting her with a single use and single exclusion right. The enclosure movement of eighteenth century England is a leading example. Access to communally used fields was restricted and land was converted to large private farming estates (Smith 2000). The second solution is to subdivide the landscape into parcels and assign a single exclusion and single use right per parcel. Examples of privatization schemes like this include homesteading in the United States, Canada, and Australia during 18th and 19th century (Allen 1991), programs in modern sub-Saharan Africa (Mwangi 2007), and the allotment of Native American lands during 1887-1934.

Sole private ownership is a useful theoretical construct but subdivision is the empirically dominant form of privatization. It is a politically feasible alternative that can solve overuse and underinvestment problems in agriculture as long as parcels are not too small for viable farming.[10] Next, we summarize potential drawbacks to subdivision.

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[9] Group exclusion distinguishes common property from open access (Dietz et al. 2003, Ostrom 1990). Merrill (1998, 730) argues that the ability to exclude is crucial for private property: "Give someone the right to exclude others from a valued resource, i.e., a resource that is scarce relative to human demand for it, and you give them property. Deny someone the exclusion right and they do not have property."

[10] There are several reasons why subdivision may dominate sole ownership as a solution to common property problems. First, vesting ownership of an entire resource to a single individual is politically unpopular. The enclosure movement in England generated widespread political backlash and prompted a generation of classical economists including Adam Smith and David Ricardo to consider "land rents" as a fundamental source of economic value. Second, sole ownership creates principle-agent problems because tenant farmers are not the resource owners (Barzel 1997, Smith 2000, Allen and Lueck 2003).

B. Subdivision and the Creation of Anticommons

Whereas common property problems are due to the lack of exclusion rights, anticommons are caused by too many exclusion rights. Heller (1998) draws attention to the problem by describing underused Russian resources in the wake of post-Soviet privatization. The problem, according to Heller, was that the privatization scheme allocated exclusion rights to too many people, creating contracting barriers to fuller resource use. Heller (2008) gives other examples of anticommons – oyster beds in Maryland, real estate markets in Manhattan, and global pharmaceutical markets - and he describes two channels through which resource use is stymied. First, it can be costly to identify and contract with everyone with ownership claims. Second, attempts to gain consensus on Pareto improving resource use can fail due to individually rational but socially wasteful efforts to capture more of a project surplus. We label the first channel "transaction costs" and the second as "coordination failures."

Buchanan and Yoon (2000) formalize Heller's reasoning on the coordination channel with a model intended to demonstrate how the underuse of a fixed resource worsens with the number of owners holding exclusion rights. They argue that an anticommons is an externality problem, caused by an input assembly requirement. If multiple agents have the right to exclude others from the use of a required resource, each will fail to consider the effect on others when setting their own use fee. The resulting aggregate price exceeds the income-maximizing price, resulting in underutilization relative to sole ownership.[11] The transaction cost channel also causes underutilization, because the net return from transitioning to a new resource use is lowered by the assembly costs of contracting with each owner.

Subdivision solves the commons problem for agriculture described above and it does not in general create an anticommons *for agriculture* because the scale of exclusion rights matches the scale of profitable agricultural use, by design. In our empirical case, for example, land was typically subdivided into square parcels that varied in size with rainfall conditions in an effort to create individually profitable units based on historical farming technology.[12] Subdivision may, however, create an anticommons for any resource with a use that requires coordinated agreement across multiple parcels.

The problem is perhaps best illustrated using the parking lot example from Buchanan and Yoon (2000). There are two parking lots, one near and one distant. A tragedy of the

[11] Mitchell and Stratmann (2015) provide a rare empirical test in the context of cell phone use and find evidence of higher prices in cases with more exclusion rights.

[12] These efforts were not always successful. Bleakley and Ferrie (2014) explain how the 19th century subdivision of parcels that were too small for productive agriculture in the U.S. state of Georgia necessitated difficult contracting in order to combine the small parcels into larger, economically viable parcels.

commons arises if no one holds exclusion rights for the nearer parking lot and it becomes congested to the point where its value is dissipated. In contrast, an anticommons occurs if multiple users hold exclusion rights to the entire lot, so that anyone wishing to park must purchase a ticket from each exclusion-right holder. Sole ownership of the lot averts both tragedies. To extend the analogy to the case of subdivided ownership, imagine users are allocated property rights to individual parking stalls so there is a single use and exclusion right per stall. This solution solves both problems because the scale of use and exclusion rights match, *at the scale of resource use* (a single stall).

The problem we study arises when a new use for the resource is discovered that exceeds the spatial scale of subdivision. Suppose a developer wishes to convert the parking lot to an office building or a public park. To undertake lot-scale investment, the developer must identify and contract with each stall owner because each holds an exclusion right. Similar kinds of spatial anticommons can arise when subdivision fails to anticipate a larger scale (or different shape) of economically profitable resource use in the future and inadvertently raises future costs of transitioning to the new uses. Square 160 acres parcels, for example, do not match well with the optimal scale of land use for horizontal shale drilling, wind energy from a line of turbines, linear biking trails, and wildlife habitat.

Before proceeding, we emphasize that subdivision of surface parcels can create commons or anticommons problems for subsurface use. Consider shale versus conventional oil. Shale oil is tightly trapped and relatively immobile. Profitable extraction of it requires the exploitation of a large contiguous subsurface area via horizontal drilling and fracturing. Hence, subdividing shale ownership creates an anticommons because it grants multiple exclusion rights to a swath of shale that can be economically exploited only as a large contiguous unit. Oil in conventional reservoirs is different because it can migrate across property lines, making exclusion rights to it costly to enforce.[13] Subdivision above the reservoir grants multiple use rights because any surface owner can deplete the reservoir, resulting in a commons. The upshot is that conventional and shale oil pose symmetric problems—commons and anticommons—with the same solution: sole ownership.[14]

[13] One landowner can deplete the resource without physically accessing the subsurface below his neighbor's land by sucking oil from under his neighbor's parcel (Libecap and Wiggins 1984, Wiggins and Libecap 1985).
[14] A large empirical literature illustrates cases in which sole ownership appears to solve common-property problems of redundant capital and premature extraction in settings ranging from conventional oil drilling (Libecap and Wiggins 1984), commercial fisheries (Deacon et al. 2013), and groundwater extraction (Pfeiffer and Lin 2012). Similarly, research also finds that effective common pool resource use is confounded by large numbers of users (Agrawal and Goyal 2001). There is less empirical literature on the extent to which sole ownership solves the problem of underinvestment when natural resources are burdened by too many exclusion rights. Some applications in land conservation indicate that hiking and biking trails are more likely to be

Sole private ownership of large contiguous landscapes is rare, at least in the United States, but government ownership is not. On one hand, contiguous government ownership has the advantage of a sole private owner if a single public decision maker "holds the core bundle of property rights relatively intact" (Heller 1998, 682). A prospective oil developer can negotiate with the entity-decision maker rather than a large set of individual parcel owners thereby circumventing transaction costs and coordination problems. On the other hand, the government agent is less incentivized to act in ways that maximize the value of natural resources it manages and "may not perceive lost revenue … to be central to their decision-making" (Heller 1998, 655). Government may also sell resources at a price that is too low because of short planning horizons: there is evidence of this happening in other settings, such as the case of forest sales approved by local governments in Indonesia (see Burgess et al. 2012). These issues are important in interpreting results from our empirical tests, which compare oil development across private parcels versus government lands.

III. Theory

In this section we provide a framework for understanding how subdivided ownership might reduce oil production from shale through transaction costs and through coordination failure mechanisms reviewed in section II. We begin with a description of technology and then model anticommons in this context.

A. Drilling Technology and Spatial Scale

Although fracking and horizontal drilling were experimented with for several decades, their large-scale use did not emerge in the U.S. until about 2005 (Zuckerman 2013). A well is first drilled vertically to the depth of the shale, which runs parallel to the surface and holds the trapped oil. The well is turned horizontally and driven for typically several thousand feet through the shale. When hydraulic fracturing is added, a liquid solution is pumped at high pressure through the well. The pressure fractures the shale, thereby facilitating oil drainage from several meters in either direction of the lateral (i.e., the horizontal portion of the well). Oil is pumped out of the well until the area around the lateral is drained (Fitzgerald 2013).

The economic costs of drilling comprise two main components, aside from leasing. First, there is a large fixed cost of drilling the well associated with employing the necessary labor and capital (a drilling rig) and creating the necessary infrastructure (e.g., pipeline, waste

provided by large scale landowners –private and public - than by small landowners in a subdivided landscape but these applications rarely make connections to anticommons explicit.

water impoundment facilities, compression stations).[15] Second, there is a marginal cost of extending the lateral further (horizontally) into the shale. This marginal cost increases with distance, at least on a per unit of oil drained basis (Syed 2014).[16]

The technological costs of drilling a shale area are minimized by optimizing a horizontal length that trades-off the fixed cost of drilling additional wells versus the rising marginal cost of lateral length. We denote this length with h^*, and the associated minimized cost $c|_{h=h*}$ with 'c'. We interpret this length as defining the spatial scale of drilling, and consider it fixed.[17]

B. Project Surplus and Transaction Costs

If it is costless to contract with shale owners, the expected surplus from a well is $S = pq - c$, where p is the expected price of oil and q is the expected quantity of oil output per well. Abstracting from uncertainty and discounting, S represents the expected present value of drilling the well.[18] Changes in any parameter can change whether or not a project yields positive surplus in expectation, thereby influencing the probability of drilling. Kellogg (2014) highlights the importance of accounting for volatility when analyzing the effect of expected output price and other parameters on the drilling decision. We take those dynamics – and the interest rate - as given and focus on how changes in leasing behaviour alter the drilling decision. We do allow for variation in c across space such that c is distributed uniformly across drilling projects between a lowest and highest cost $[\underline{c}, \overline{c}]$. Cost differences arise from differences in the depth of shale and other site specific constraints on drilling.

In reality it is costly to contract with shale owners, and the transaction costs of contracting rise with the number of exclusion rights holders (N) over shale length h^*. These costs include title searches to find and evaluate mineral ownership claims, and legal costs of writing and recording formal leases.[19] In section IV we emphasize that transaction costs can be high on

[15] This cost is roughly in the range of about $10 million for a well in the Bakken formation.

[16] We are simplifying the technology; in reality production per horizontal foot declines with distance (Syed 2014) but this can be modelled as rising marginal costs per unit of oil captured because the decline in productivity can be offset by increased input use (such as care, time, fluids, energy usage, etc.) There is also a marginal cost of drilling depth that we ignore here. This cost tends to increase linearly with depth (Syed 2014).

[17] In practice drilling companies could shorten line lengths to reduce exposure to anticommons. Allowing line length to adjust would increase the scope for profitable projects in our model, but it would not change the fundamental conclusions that larger N reduces drilling probabilities and expected payments.

[18] A more realistic expression is $E(S) = \sum_{t=1}^{T} \rho^t E(p_t q_t) - c$, where T is the life of the well, which is projected to be about 25-30 years in our study area, q_t represents declining production over time, E(p_t) indicates expected prices over the life of the well, and ρ^t is a discount factor. We abstract away from uncertainty and dynamics because making these features explicit would add bulk to the theory without providing additional insights.

[19] These costs are typically borne via payments to so-called "landmen." These are agents whom oil companies hire to find rights holders and negotiate leases with them.

Indian reservations where heirship ownership – particularly of minerals – is often poorly documented. To the extent ownership is documented, time consuming effort is still required to pore through inventories and title histories (Shoemaker 2003).[20] Regardless of how the surplus is shared between an oil company and shale owners, transaction costs act as a tax on the value of the shale.

Adding transaction costs, the surplus of a drilling project is $S = pq - c - \tau N$. Here τ is a parameter denoting the transaction costs of obtaining leases from *N* mineral owners, assumed to be linear. Holding constant the other parameters, expected surplus from the drilling project declines with *N*. This implies that profit-seeking drilling companies are less likely to drill in shale areas with high *N* unless the transaction costs of high *N* are offset by reductions in the share of surplus allocated to shale owners. If large *N* renders expected surplus negative ($S < 0$), oil companies will not engage in lease negotiations in this simple framework.[21]

C. Allocation of Surplus via Royalty Payments

Most compensation to shale owners is in the form of royalty payments (Brown et al. 2016). With royalty payments, the project-level expected profit for the oil company is

(1) $\pi = (1-R)pq - c - \tau N$.

Here, *R* denotes the aggregate project-level royalty rate which is $= \sum_i^N w_i r_i$. Each individual shale owner charges $r_i \in [0,1]$ and $w_i \in [0,1]$ are weights representing the proportion of owner *i's* mineral acreage in the project. We assume equal shares so that $R = \sum_i^N r_i / N$. Holding constant the other parameters, expected profit is declining in *R*. In what follows, we assume drilling occurs only if $\pi \geq 0$.

D. Coordination Failure

We now apply the Buchanan and Yoon (2000) 'coordination failure' framework. In their framework, each of *N* excluders to a resource charges an individual price for use. Permission to use the resource is not granted unless each of *N* owners consent. Consent is granted only if asking prices are paid. Each shale owner chooses a royalty rate in an attempt to maximize his

[20] Shoemaker (2003, 761) notes that any informed transaction on fractionated Indian reservation land "…can be accomplished only if accurate records can be acquired and understood ..."

[21] Shoemaker (2003, 760) cites an example in which an oil company did not complete a lease "…after realizing how much work was involved in obtaining the necessary signatures from 101 heirs, of whom the BIA had no address for 21 and 6 were deceased with estates still pending agency probate." This is a case in which the transaction costs apparently prevented leasing from occurring.

expected payout. [22] The expected payout is the probability the project will be drilled multiplied by the payout, conditional on drilling.

Initially, we model requested royalty rates under the assumption that transaction costs of τN have already been paid by oil companies and are sunk (e.g., to discover the identities of the relevant shale owners). This means that drilling will occur only if expected net revenue exceeds costs that have not yet been incurred, or if:

(2) $(1-R)pq - c \geq 0$

We assume shale owners cannot directly observe the driller's project-specific cost, c. To the shale owner, c is a random variable that induces uncertainty about how changes in the royalty rate affects the drilling decision. This allows us to express the probability of drilling terms of the CDF for c as $Pr(Well) = \Pr[(1-R)pq - c \geq 0] = \Pr[c \leq (1-R)pq] = F[(1-R)pq]$.

Assuming that shale owners know that costs are uniformly distributed over $[\underline{c}, \bar{c}]$, then

(3) $$Pr(Well) = \begin{cases} 0 & for \quad (1-R)pq < \underline{c} \\ \frac{(1-R)pq-\underline{c}}{\bar{c}-\underline{c}} & for \quad (1-R)pq \in [\underline{c}, \bar{c}) \\ 1 & for \quad (1-R)pq \geq \bar{c} \end{cases}$$

We focus on the interior portion of the CDF in (3), where the probability of drilling is a continuous function of the royalty rate. The royalty rate has no effect on the probability of a well for projects where $(1-R)pq$ falls outside $[\underline{c}, \bar{c})$.[23]

Each shale owner maximizes his expected payout, given by

(4) $$E(pay_i) = \Pr(well) \times (pay \mid well = 1) = \frac{(1-R)pq - \underline{c}}{\bar{c} - \underline{c}} \times \frac{pqr_i}{N}.$$

The term on the right-hand side represents the owner's payout, assuming as above equal proportional ownership of the shale. The individual's optimization problem is

(5) $$\max_{r_i} \left[\frac{(1-\sum r_i/N)pq - \underline{c}}{\bar{c} - \underline{c}} \right] \times \frac{pqr_i}{N}, \text{ with } \sum r_i = r_i + \sum r_{-i}.$$

The individual chooses a royalty rate, taking as given the rates chosen by all other shale owners in a project, denoted by $-i$. In a symmetric Nash-Equilibrium, the solution for the

[22] Shoemaker (2003, 760) describes the problem of getting co-owner consent on fractionated Indian reservation land. This can be especially problematic when "incompetent" or "recalcitrant" heirs exist.

[23] This occurs where $pq < \underline{c}$ and the potential surplus is negative, regardless of royalty rate—in these settings no leasing negotiation occurs because drilling is not feasible. On the other end of the support, we assume that $\bar{c}$ is sufficiently high to rule out situations where R has no effect on the probability of drilling. Since $(1-R)pq$ approaches 0 as R approaches 1, this just requires that pq is not infinitely larger than $\bar{c}$.

rate is given by $r_i^N = R^N = \left(\frac{N}{N+1}\right)\left(\frac{pq-\underline{c}}{pq}\right), \forall i$. We show in the appendix that R^N is increasing in *N*. This is the discrete choice version of Buchanan and Yoon's (2000) result.[24]

It is possible that τN will affect royalty rates in our setting if those costs are not considered sunk at the time of lease negotiations. When τN is not a sunk cost, the royalty rate is given by

$$(6) \quad r_i^{N\tau} = R^{N\tau} = \left(\frac{N}{N+1}\right)\left(\frac{pq-\tau N-\underline{c}}{pq}\right), \forall i$$

Note that $R^N > R^{N\tau}$ because, when transaction costs are sunk, the shale owners are able to extract more of the surplus (rent) because the driller would have to absorb additional $N\tau$ costs to drill in a different location.[25] Moreover, $\partial R^N / \partial N > 0$ while $\partial R^{N\tau} / \partial N$ is of ambiguous sign (see appendix). With transaction costs factored into the decision calculus, shale owners may respond by lowering their royalty requests as *N* grows in spite of the coordination failure mechanism. As we show below, the net effect on the probability of drilling is unambiguous.

E. Probability of Drilling

Our empirical analysis focuses on the probability of drilling as a function of *N*, the number of shale owners. The theoretical framework provides clear predictions about the effect of *N* on these outcomes. Consider the probability of a well, now given by

$$(7) \quad \Pr(well) = \frac{(1-R^{N\tau})pq-\tau N-\underline{c}}{\overline{c}-\underline{c}}.$$

We show in the appendix that $\frac{\partial \Pr(Well)}{\partial N} < 0$. That is, the probability of a well is negatively related to *N* regardless of whether or not one considers transaction costs sunk at the time of lease negotiations.

We also show in the appendix that, for a given *N*, $\frac{\partial \Pr(Well)}{\partial \tau} < 0$. This comparative static is useful for thinking about how private vs. public ownership might affect the probability of drilling. For instance, if government-owned resources are subject to bureaucratic approval, τ could be higher for government-owned parcels than for privately

[24] Buchanan and Yoon (2000) assume downward-sloping demand curve for the use of a resource with many exclusion rights, whereas we assume the investment is a yes/no decision that depends on the random variable *c*.
[25] This reflects the insight of Klein et al. (1978), who explain how relationship specific investments expose one party in a contract to rent expropriation. In our setting, an oil company that undertakes project specific investments in title searches, etc., is exposed if those investments are sunk. Williamson (1979) and Grossman and Hart (1986) provide related insights about contracting exposure to transaction costs.

owned parcels, even if $N = 1$ in both cases. While our main interest is in the spatial component of transaction costs induced by subdivision, we also investigate this more traditional difference between private and public ownership in the empirics.

F. Expected Rents and Discussion

Finally, consider how higher *N* impacts expected rents to shale ownership. Increasing *N* decreases the probability that S >0, implying that drilling projects may not move into a leasing stage due high costs of identifying owners, title searches, etc. Higher *N* also lowers the probability of drilling, conditional on leasing. At the same time, higher *N* raises payouts conditional on drilling, if transaction costs are considered sunk. We show in the mathematical appendix that the net effect is negative: higher *N* reduces the aggregate expected payout to resource owners. This is the key result of Buchanan and Yoon (2000), and the implicit argument in Heller (1998, 2008), stylized to our setting. Individually optimal exclusion decisions lead to socially wasteful underuse, in that they reduce expected rent.

Two clarifications are useful before proceeding. First, shale owners could inadvertently benefit from an anticommons if the price of oil unexpectedly increases after leases are negotiated but before drilling has commenced. In that case, drilling becomes more likely and payouts to shale owners, conditional on drilling, increase precisely because requested royalty rates were too high, in expectation. If future changes in prices and costs are all anticipated, however, then large *N* cannot benefit resource owners.

Second, the model does not consider institutional responses to the contracting problems. Forced pooling laws, passed by US states, compel minority mineral owners into horizontal drilling projects if a majority of neighboring acreage has already been leased. State-level forced pooling laws do not generally apply on sovereign Indian reservations (see Slade 1996), but a 1998 federal law specific to Fort Berthold requires the consent of only a majority of owners of allotted trust lands before a mineral lease can be executed. We view these institutional responses as decreasing but not eliminating problems modeled above.

IV. Subdivision of Shale: Natural Experiment on the Bakken

To assess the importance of anticommons, we study the subdivision of the Bakken shale. It sits beneath the Fort Berthold Indian Reservation and surrounding North Dakota land. The historical subdivision of these lands creates an ideal natural experiment. First, the "allotment", homesteading, and later flooding of Fort Berthold created three types of tenure

with different exclusion rights per parcel. Second, the subdivision of shale was inadvertent to the intentional subdivision of farm land, which occurred long before shale was profitable and even before conventional oil was discovered. The resulting patterns of modern parcel sizes, shapes, and tenure types are largely exogenous to the quality of shale that only recently became valuable via horizontal drilling.

A. Land Allotment

The allotment of Fort Berthold during the late and early 19th centuries was governed broadly by the U.S. Allotment Act of 1887. It authorized the U.S. government to sequentially subdivide communal Indian reservations and allot parcels to families and individuals (see appendix figure A1). Allotment was promoted to encourage agricultural investment and, consistent with this claim, research indicates the scale and timing of allotment across reservations was determined primarily by agricultural land quality (Carlson 1981). [26]

The Act allotted land to Indians with the intention of granting private ownership including the right to alienate after 25 years or once the allottee was declared "competent." The distribution of arable land was as follows: 160 acres to each family head, 80 acres to each single person over 18 and orphans under 18, and 40 acres to each other single person under 18. On reservations for which total acreage exceeded that necessary for allotments, the surplus land was privatized and opened for white settlers.

The Indian Reorganization Act (IRA) of 1934 halted further privatization, declaring those acres not already alienated to be held in trust by the Bureau of Indian Affairs. Allotted lands not privatized prior to 1934 are held in trust to this day, and interests in the land are divided among the heirs of the allottee. The allotted trust parcels on Indian reservations today often have multiple owners with exclusion rights, sometimes more than 100 (Russ and Stratmann 2017). On the Fort Berthold reservation, a government study reported the following breakdown of ownership: 13 percent of allotted trust tracts had two owners; 38 percent had 3-10 owners; 26 percent had 11 to 25 owners; 14 percent had 26 to 50 owners; and 8 percent had more than 50 owners (U.S. Government Accounting Office 1992).

Allottees on Indian reservations, settlers who acquired surplus lands, and homesteaders before 1916 also acquired subsurface rights to oil, even if it was not yet discovered. After 1916, the Stock-Raising Homestead Act split oil ownership, reserving

[26] The sponsor of the Act, Senator Henry Dawes, argued that under communal ownership Indians had not "…got as far as they can go because they own their land in common, and under that [system] there is no enterprise to make your [land] any better than that of your neighbors." The quote is cited from Ambler (1990, p. 10).

subsurface rights to the federal government on new homesteads. For reservations not yet allotted at this time, subsurface rights under future allotments were often reserved for tribal governments by specific laws (Ambler 1990). In general, only reservations that were not allotted, or that were allotted after the mid-1910s, have communal mineral interests fully intact today.

B. Shale Ownership under Fort Berthold

The Fort Berthold Indian reservation, depicted in Figure 1, was established in 1851 by treaty. Though the treaty established a reservation of over 12 million acres for three tribes – the Arikara, Mandan, and Hidatsa – subsequent policies reduced the reservation to its contemporary size of 988,000 acres. Congress approved Fort Berthold for allotment in 1894, and the northeastern section was opened for surplus homesteading settlement in 1910. The surface and subsurface rights in the surplus section were quickly privatized (see figure 1).[27] The majority of Fort Berthold was allotted but not released from trust. Some allotted parcels were later privatized (figure 1).

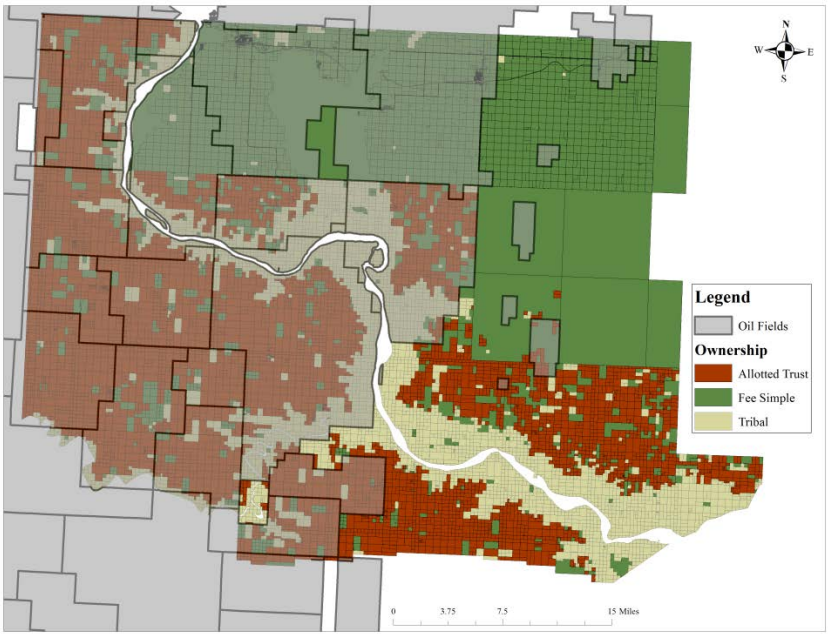
After the allotment era, 150,000 acres of land reverted back to tribal ownership when the reservation was flooded for an Army Corp of Engineers dam project in 1951. This Garrison Dam project was controversial and it forced the relocation of families off of allotted trust land near the Missouri River and into other areas of the reservation. The episode explains why so much of the tribally owned shale today is by the river in contiguous holdings (figure 1); much of the land is dry now but it was in the original flood basin. Within the part of the reservation that is on an oil field, today there are 285,651 acres of allotted mineral tenure, 176,820 acres of fee simple (privatized) tenure, and 109,016 acres of tribal tenure. Some of this area, particularly the western part of the reservation, sits above active oil fields as defined by the North Dakota Oil and Gas Commission. These are relatively homogenous areas of terrain beneath which shale can be extracted in amounts that justify drilling.

The variation in Fort Berthold parcel sizes and tenure are plausibly exogenous to the quality of shale beneath because the reservation was established, allotted, and opened for settlement long before oil was discovered. As Ambler (1990, 42-43) notes: “When it surveyed [Fort Berthold] in the 1910s, the U.S. Geological Survey … found no oil and gas

[27] Land in the surplus section was closer to a late 19th century railroad line, and it has a gentle slope, suggesting it was of higher agricultural value than the rest of the reservation. Although not the focus of our study, this observation is consistent with studies of land privatization which emphasize the endogenous selection of lands for privatization (Besley 1995, Galiani and Schargrodsky 2010, Field 2005, Akee and Jorgensen 2014).

potential, which is not surprising because oil and gas was not discovered in the state until 1951." The Dam project was approved in 1947, also before the discovery of oil.

Figure 1: Parcels and Mineral Tenure on Fort Berthold Reservation



Notes: This map depicts parcel boundaries, oil fields, and mineral tenure types on the Fort Berthold Indian Reservations. The surrounding counties are Dunn, McKenzie, and Mountrail. The data sources are described in table 2. The areas lacking parcel boundaries are areas for which parcel level data are lacking.

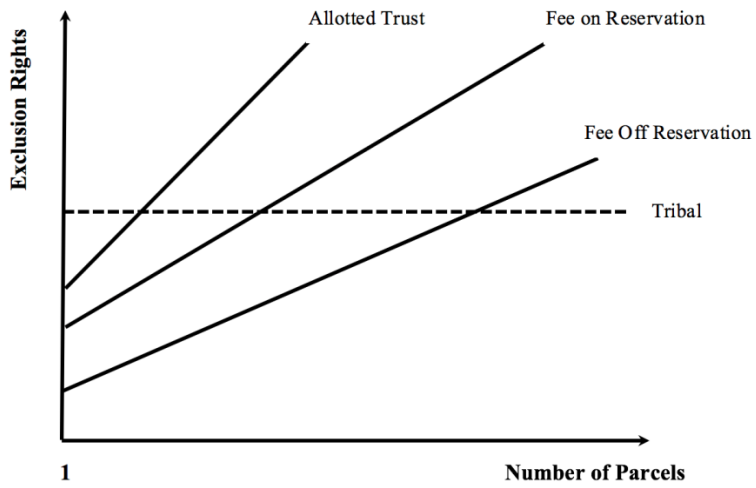
C. Natural Experiment for Anticommons Tests

Two conditions need to hold for the subdivision of Fort Berthold to constitute a valid natural experiment for the anticommons tests. First, the inadvertent subdivision of shale must not have unintentionally biased land tenure patterns and parcel sizes and shapes towards higher quality shale. We investigate this possibility empirically by examining how shale thickness and depth correspond to tenure, parcel sizes, and shapes and present the results in appendix table A1. Details of our shale quality measurements are also available in the appendix. As shown in appendix table A1, variation in tenure, parcel sizes, and shapes is verifiably exogenous to shale quality, within oil fields.

Second, the inadvertent subdivision of shale must generate meaningful variation in *N*, the number of exclusion rights over the spatial expanse of a drilling project. Figure 2 illustrates how *N* changes with subdivision across the different tenure types. Subdividing tribally owned land into finer parcels does not add exclusion rights because these "parcels" share a common owner (the tribe). Hence, the slope of the tribal line in figure 2 is zero. The slope of the fee simple line in Figure 2 is one because, as land is subdivided into fee parcels,

the number of exclusion rights increases by one owner for each parcel added. The slope of the allotted trust line is steeper because each allotted parcel has multiple owners and so carries with it multiple exclusion rights—99 percent of allotted trust parcels on the Ft. Berthold Reservation have more than one owner (GAO 1992). The slope of the off reservation line is less than one because, as discussed in section III, off reservation parcels are subject to North Dakota forced pooling laws. This is a rationale for why *N* may grow at a slower rate off of the reservation.

Figure 2: Number of Exclusion Rights (N) over Lateral of Length *h**



The vertical intercepts in Figure 2 depict the number of excluders for whom consent would be needed if the entire lateral was under a single, large parcel. For off reservation parcels, the parcel owner must grant permission and a permit is required by North Dakota. For fee parcels on the reservation, a tribal agency may also be involved in granting permission. For allotted parcels, multiple owners of the single parcel must grant permission and permits are required by multiple federal agencies such as the Bureau of Indian Affairs and the U.S. Bureau of Land Management (Regan and Anderson 2014, Kunce et al. 2002).[28] For tribal parcels, multiple tribal agencies are also typically involved – especially if there are archaeological and cultural considerations regarding surface disturbances. For these reasons, we have drawn figure 2 under the assumption that tribal ownership engenders more veto power (exclusion rights) that must be overcome before a drilling project is launched, regardless of spatial extent. Alternatively, the higher intercept may be interpreted as a higher transaction cost parameter (τ) for tribal projects, as in our theoretical framework (see section

[28] Drilling under allotted trust land and tribal land does not formally require permission from the state of North Dakota but the oil and gas regulations of the state and the permitting process is generally followed.

III). These assumptions mean, for example, not only that there is more red tape in government decision making but also that approval over controversial projects such as fracking requires more administrative procedures and consensus gathering.

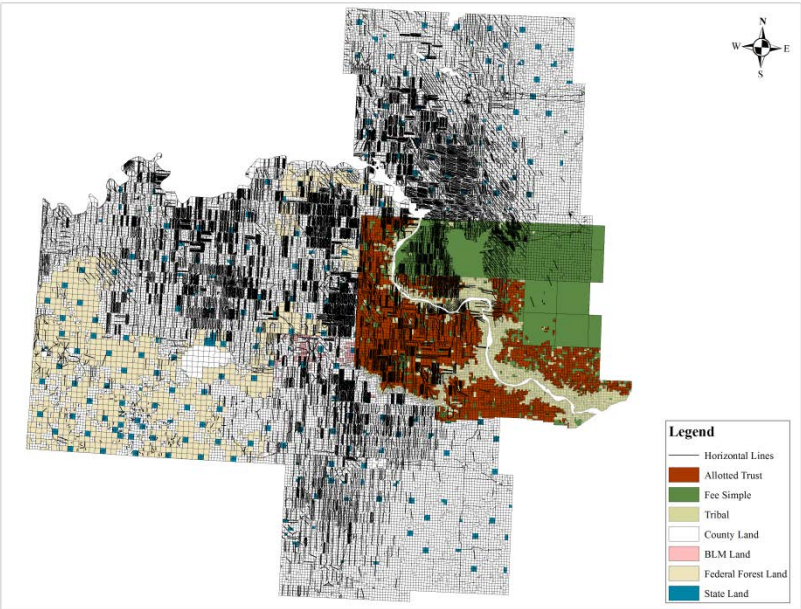
V. Data for Empirical Tests

To assess the effects of subdivision and tenure on horizontal drilling, and expected rents from shale ownership, we develop parcel-level, well-level, and lease-level data sets. We describe the data sets in detail, after first providing an overview.

A. Overview

The key outcome variables measure the location and timing of horizontal wells drilled into the Bakken during the boom of 2005-2015. The source for data on drilling is the North Dakota's Oil and Gas Commission website. It contains GIS data for every horizontal well bore, and for every lateral, that has been drilled in the state. Our data set represents the accumulation of wells completed as of May 1, 2015, which roughly corresponds with the beginning of a drilling 'bust.' During this 10-year period, 7,864 horizontal wells were drilled in the study area spanning 12,017 miles. Figure 3 shows the wells in the study area.

Figure 3: Location of Wells Drilled during 2005-2015 in Study Area

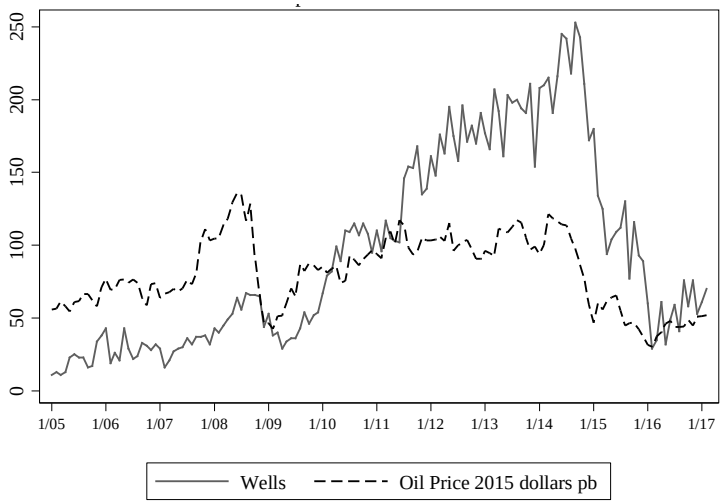


Notes: This map depicts the location all horizontal oil wells drilled through May 2015, based on data from the North Dakota Oil and Gas Commission.

Figure 4 shows the new wells drilled during 2005-2017. Our study area, the Bakken oil field, produced the vast majority of these wells and accounted for 1.56 billion barrels of

oil.[29] To understand the potential magnitude of royalty payments, multiply the average price per barrel over 2005-2015, which was $85.5 in 2015 dollars, by the average royalty rate, which was 17.4 percent. This amount - $14.9 billion –does not account for the flow of royalty payments earned on oil extracted over the well's full lifetime of perhaps 25 years (MacPherson 2012).

Figure 4: New Wells in North Dakota and Global Oil Prices, 2005-2017



Notes: The source for drilling information in North Dakota is https://www.dmr.nd.gov/oilgas/. The oil price data come from the U.S. Energy Information Administration (west texas intermediate) and are adjusted to 2015 U.S. dollars based on the U.S. CPI. Oil prices are per barrel. The source for oil drilling in our study area is the North Dakota's Oil and Gas Commission website.

B. Parcel-Level Data Set

Table 1 shows summary statistics of the parcel-level outcome variables that we have constructed. The full data set consists of 51,083 parcels but we constrain our attention to the 41,979 parcels on oil fields, which are the areas in figure 3 containing dense wells. For the reservation, we obtained parcel-level GIS data on mineral tenure for allotted and tribal parcels from the Bureau of Indian Affairs (BIA) in addition to GIS data on which areas of the reservation have fee simple mineral rights. Because the BIA does not identify the parcel boundaries for fee parcels, we overlapped the reservation tenure files with GIS data on parcels for Dunn, McKenzie, and Mountrail counties to fill in the missing parcel boundaries.

The outcome variables indicate if a parcel has been drilled, and the extent to which a parcel has been exploited. Approximately 41.6 percent of the sample parcels have been cut by at least one lateral. Having a lateral is our best proxy for whether or not the owner(s) have received financial payment for their shale.[30] We measure the extent of drilling through a

[29] https://www.dmr.nd.gov/oilgas/stats/2015CumulativeFormation.pdf

[30] In some unusual cases, it is possible for an owner to receive compensation if a line does not cross his parcel. Compensation is based on membership in an oil drilling unit, and sometimes a line does not cross every

parcel by the miles of laterals beneath that parcel. Some parcels are drilled multiple times from multiple directions or at different depths. The mean number of line miles per parcel is 0.27. The presence of a well bore on the parcel is an indication that the surface owner has received payment for accommodating drilling infrastructure. Approximately 7.9 percent of the parcels have at least one well bore.

We include measures of parcel size, shape, and tenure to proxy variation in transaction and coordination costs. The variable Parcel Longside measures the length of a parcel's longest side. Holding constant the parcel's acreage, an increase in the longside means the parcel has a longer and skinnier shape. The other variables indicate the ownership and tenure of the parcel.[31] Not included in the summary statistics are indicators for parcels owned by the U.S. forest service, the U.S. Bureau of Land Management, and the state of North Dakota. These categories collectively comprise 4.7 percent of the sample parcels.

To assess the effects of subdivision and tenure mixes around a parcel, we focus on parcels within a 1-mile radius of each parcel's centroid. Figure 5 illustrates our mapping from the spatial data to the variables. We choose the 1-mile radius because lines from well bores typically extend 1 to 2 miles but our results are robust to other distance choices.[32] Within the 1-mile radius, the number of neighboring parcels ranges from 4 to 1000. Note that the data sets treat government tracts, including tribal tracts, as multiple separate parcels, even though the tracts have a single government agency owner. Some mineral parcels are under a body of water, based on the high flood lines of the Missouri River. We control for this, to account for special rules governing drilling under water.

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member's parcel. Lines usually cross every parcel in a unit, with the exception of very small parcels. We discuss unitization in more detail below.

[31] The parcels represent oil ownership on the Fort Berthold reservation. The parcels off the reservation represent surface ownership, because we do not have data on off-reservation mineral rights. Surface and mineral ownership were generally aligned before oil development, because much of the land in North Dakota was settled before the Homestead Act of 1916 , which reserved subsurface mineral rights to homesteaded land settled thereafter to the United States.

[32] An alternative approach is to conduct analysis at the level of an oil spacing unit. Unitization laws require the driller to define a "unit", which is a contiguous area of minerals that will be exploited. Royalty compensation to each mineral owner is determined by their percentage of acres in a unit. While analyzing unitization data from the North Dakota Oil and Gas Commission, we discovered that these are not good candidates for our spatial observations because their definition is highly endogenous and time variant. Unit sizes vary in size over time; from a low of 160 acres to a high of 5120 acres. As of 2015, the most prevalent unit sizes were 1280 acres and 640 acres. These units are typically rectangular, reflecting the fact that wells are drilled over long narrow swaths of space. However, oil units are highly fungible on the Bakken and they change definitions frequently, as new parcels are appended and other parcels eliminated. Most parcels in the Bakken have been part of multiple units over time, sometimes as many as 20. This fungibility of units in the case of horizontal shale drilling is much different than unitization over traditional oil reservoirs (Libecap and Wiggins 1984, Wiggins and Libecap 1985).

Table 1: Summary Statistics from Parcel Level Data Set

	Mean	*Std. Dev.*	*Min*	*Max*	*Description*
Outcome Variables					
Lateral Indicator[a]	0.4163	0.4929	0	1	=1 if the parcel was cut by at least one lateral as of May 1, 2015, otherwise = 0
Miles of Horizontal Lines[a]	0.2784	0.5584	0	10.47	The total length (miles) of laterals cutting a parcel as of May 1, 2015
Parcel Size, Shape, and Tenure					
Parcel Acres[b, c]	79.402	98.197	5.16e-09	1259.9	Area of the parcel, in acres
Parcel Longside[b, c]	0.4273	0.3553	9.25e-06	8.046	The length of a parcel's longest side, in miles
Reservation Parcel Indicator[b]	0.2419	0.4283	0	1	=1 if the parcel is on the Fort Berthold Indian reservation, otherwise =0
Fee Parcel Indicator[b]	0.0991	0.2988	0	1	=1 if the reservation parcel is fee simple, otherwise =0
Allotted Trust Parcel Indicator[b]	0.0911	0.2877	0	1	=1 if the reservation parcel is allotted but not alienated from trust, otherwise =0
Tribal Parcel Indicator[b]	0.0517	0.2988	0	1	=1 if the reservation parcel is tribally owned, otherwise =0
Neighbor Parcels (1-mile radius)					
No. of Neighors	153.92	251.22	4	1000	Number of parcels within 1 mile radius around parcel
St. Deviation of Neighbor Size	9.9673	9.3553	0.0196	119.27	Standard deviation of parcel acreage within 1 mile radius around parcel
Off Res. Neighbors[b, c]	104.66	212.27	0	993	Number of private parcels, off the reservation, within 1 mile radius around parcel
Fee Neighbors[b, c]	37.307	165.80	0	1000	Number of fee parcels within 1 mile radius around parcel
Allotted Trust Neighbors[b, c]	5.7433	14.327	0	131	Number of fractionated parcels within 1 mile radius around parcel
Tribal Neighbors[b, c]	4.0566	12.073	0	104	Number of tribal parcels within a 1 mile radius around parcel
Neighbors Underwater [f]	4.9241	14.869	0	119	Number of parcels under a body of water within 1 mile radius around parcel
Extra Tenure Regimes[b, c]	0.2805	0.5700	0	6	No. of extra tenure types adjacent to parcel (off res, fee, allotted, tribal, USFS, BLM, state)
Other Covariates					
Thick-Depth Ratio[d]	0.0098	0.0034	0.0013	0.0182	Shale thickness divided by shale depth
Feet to Water (000s)[f]	12.231	10.313	0	43.759	Euclidean distance (in 000s of feet) from parcel centroid to nearest body of water
Feet to Railroad (000s)[f]	14.078	11.851	0	57.403	Euclidean distance (in 000s of feet) from parcel centroid to nearest railroad line
City Indicator	0.1042	0.3056	0	1	= if the parcel is within a city boundary, otherwise = 0
Road miles in 1-mile radius [f]	8.7415	18.626	0.0967	57.40	Number of road miles within 1 mile radius of parcel centroid, divided by area acres

Notes: This table summarizes data for all parcels over an oil field. N = 43,166 for all variables except the Thick-Depth Ratio, which is N = 41,376. Data sources are: a) North Dakota Oil and Gas Commission website, b) U.S. Bureau of Indian Affairs, c) Real Estate Portal, d) U.S. EIA website e) Authors calculations from National Elevation Dataset, and f) Authors calculations from North Dakota GIS Portal data.

We create a variable to measure the mix of tenure types around a parcel. The variable 'Extra Tenure Regimes' is the number of tenure types represented by the block of parcels adjacent to the parcel. For example, a fee-simple parcel adjacent to fee, tribal, and allotted trust parcels has two extra regime types in its neighborhood. Figure 5 illustrates.

Figure 5: Examples of Mapping from Spatial Data to Empirical Variables

Notes: These images illustrate how we have constructed our empirical variables. For the parcel-level analysis, parcel *i* is in bold. The dependent variables include the timing of the first lateral under parcel *i*, the miles of lateral penetrating parcel *i*, and indicators for whether or not a vertical well bore is found on parcel *i*. In the figure on the left, there are laterals through parcel *i* but not a well bore. In the figure on the right, there are laterals and a well bore on parcel *i*. The number of neighboring parcels includes all parcels that are contained within or touch the exterior boundary of the radius. The number of extra regimes is measured by the count of different tenure types that are directly adjacent to parcel *i*. For the well-level regressions, the key dependent variables measure the date in which the entire well (bore plus laterals) was completed. The other dependent variable in the well-level regressions measures the total length of the lines emanating from the well bore. The key right-hand side variables in the well-level regressions measure the tenure of the parcel containing the well bore, and the number and tenure of the parcels through which the laterals penetrate. The images above do not show all of the wells and laterals in the area, in order to keep the images simpler and more informative.

Finally, we have collected data to measure a variety of parcel-level factors that may influence the net value of extracting oil. One of these variables is a measure of shale quality discussed in the appendix (and found to be uncorrelated with tenure and ownership within oil fields). This variable is the shale's thickness-to-depth ratio. A higher ratio measures higher quality of shale because thicker shale tends to hold more oil and shallower shale is less costly to access. We have also created a "topographical roughness" variable to account for potentially higher costs of drilling through rough terrain. We have also created variables measuring the distance from each parcel's centroid to the nearest body of water (zero if the parcel is under water), and to the nearest railroad. We measure transportation infrastructure in the neighborhood around a parcel with the miles of roads in a 1 mile radius. Finally, although not shown in Table 1, we include the spatial X-Y coordinates of a parcel in some specifications to control for possible South-North and West-East patterns in drilling, and to control for unobserved spatial variation in shale quality or access costs.

C. *Well-Level Data*

The well-level data set comprises the 6,554 horizontal wells for which we were able to match the bore with the laterals emanating from the bore.[33] The number of tenure regimes penetrated by laterals from a single well range from 1 to 3. Ninety-one percent of the lines from a well are contained within a single tenure regime for the entire sample, but 61 percent penetrate multiple regimes for wells drilled on the reservation. The mean number of parcels cut by laterals is 7.3 parcels. Figure 5 illustrates an example of how our well-level variables map to the spatial attributes of a well, and table 2, panel A gives summary statistics.

We have also estimated the discounted revenue generated from a well during its first 18 months of production. From the data we have in hand, we observe $Q_{\tilde{T}} = \sum_{t=0}^{\tilde{T}} q_t$ where t = month, $\tilde{T}$ = number of months since production began, and $Q_{\tilde{T}}$ is cumulative production as of early 2017. We do not observe q_t , which is the monthly flow of oil. We estimate q_t by combining the information on production starting month, and cumulative production, with data from a representative (baseline) oil decline curve on the Bakken. The oil decline calculations we use are based on the monthly productivity from the baseline well, as estimated by Hughes (2013, p. 57). According to his estimates, the baseline well produces 213,488 barrels during the first 48 months. Production from the well declines rapidly at first, and then the decline rate slows. We fit a hyperbolic decline-curve function (Satter et al. 2008) to the Hughes figures in order to extend the production estimates from 4 to 29 years, which is a predicted length of production (MacPherson 2012). This process leads us to estimate total production of 396,395 barrels in 29 years (348 months), which is a conservative estimate.[34]

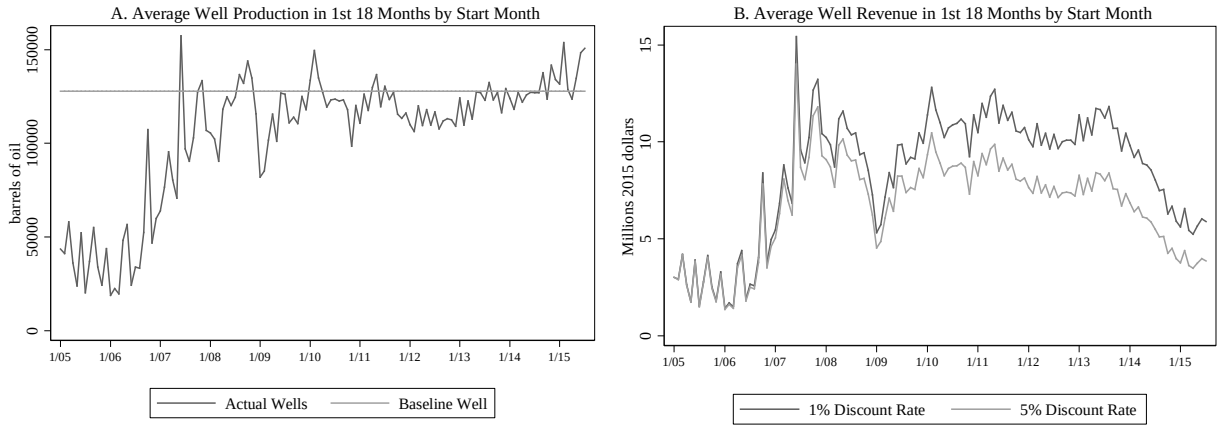
From the oil-decline curve, we estimate the lifetime oil-productivity of each sample well and then infer productivity over the first 18 months. We limit the analysis to 18 months because we can only observe world oil prices for about 18 months after our sample ends, which is May 2015. We combine these estimates with monthly price data to estimate the revenue earned by each well.

Figure 6 graphs a summary of the results. Panel A plots average well productivity by the month in which production began. Well productivity has been stable since early 2008 with a slight upward trend due to improvements in drilling technologies. Panel B plots average well

[33] We match well bores to laterals by matching first on API number and then using proximity.
[34] Note that this "baseline" well from Hughes (2013) is less productive than other estimates. MacPherson (2012), for example, reports that a typical well should produce 540,000 barrels over its lifetime.

revenue by the month in which production began. The graph indicates that wells drilled after late 2013 earned lower revenue than wells drilled during 2010-2013. This is due to falling oil prices in mid-2014 (see figure 4). Panel B also shows the impact of discounting. At a five percent annual rate, the revenue disadvantage of being drilled later in time, relative to January 2005, is more significant than at a one percent discount rate.

Figure 6: Estimated Production and Revenue from Sample Oil Wells
(first 18 months of production)



Notes: We estimated oil production during the first 18 months using the following procedures. First, we match oil wells from the North Dakota Oil and Gas Commission with oil wells in DrillingInfo.com by API number. This provides well-specific data on (a) the first month of production and (b) cumulative oil production through the beginning of 2017. Second, we estimated the proportion of cumulative well production from a baseline oil decline curve by Hughes (2013, pg. 57) and depicted by the "baseline well" line. Third, we used the baseline oil decline curve to estimate cumulative production, and to back-out an estimate of production over 18 months. To create the average well revenue figures, we multiplied estimated monthly production by the monthly world price of oil, deflated to $2015 dollars. We discount estimated revenues using 1% and 5% annual discount rates.

D. Lease-Level Data

We acquired lease data from DrillingInfo.com, which reports acreage, lease date, production status, approximate location, and royalty rates for each lease. Leases are geo-referenced to the PLSS section where production takes place, so we cannot directly match leases to our parcel or well level dataset. Rather, we match leases to PLSS sections (1 square mile units or 640 acres in the land surveying system) and then calculate the total number of parcels in each section in addition to aggregating all of our other parcel-level covariates up to the PLSS section level.

Based on discussions with support staff at DrillingInfo, we learned that their lease data have an important limitation—while DrillingInfo's data set has information on every *unique* oil and gas lease in our sample area, their data collection methodology is to only

Table 2: Summary Statistics from Well and Lease Level Data Sets

	Mean	*St. Dev.*	*Min*	*Max*	*Description*
Panel A: Well Data					
Day when Drilled[a]	2314.0	739.73	13	3772	Days elapsed between January 1, 2005 and date in which the lateral was drilled
Laterals from Well Bore[a]	2.2223	0.6248	1	12	Number of laterals stemming from well bore
Miles of Laterals[a]	1.8896	0.5091	0.0002	8.1336	The total length (miles) of laterals from the well
Revenue 1% DR [b]	9.5069	5.2280	0.0069	73.197	Estimated revenue during first 18th months, discounted from 2005 (in millions of 2015 $s)
Revenue 3% DR [b]	8.2073	4.5987	0.0062	64.074	Estimated revenue during first 18th months, discounted from 2005 (in millions of 2015 $s)
Revenue 5% DR [b]	7.0982	4.0748	0.0057	56.100	Estimated revenue during first 18th months, discounted from 2005 (in millions of 2015 $s)
Fee Parcel Indicator[a, c]	0.0876	0.2828	0	1	=1 if the well bore is on fee simple parcel
Allotted Trust Parcel Indicator[a, c]	0.0992	0.2989	0	1	=1 if the well bore is on allotted trust parcel
Tribal Parcel Indicator[a, c]	0.0079	0.0886	0	1	=1 if the well bore is on tribal parcel
Off Res. Parcel Indicator[a, d]	0.7700	0.4208	0	1	=1 if the well bore is on an off reservation
Tenure Regimes[a, c]	1.1030	0.3527	1	3	Number of different tenure regimes that all laterals from a well penetrate
All Parcels[a, c, d]	7.2237	3.7259	1	85	Number of parcels that all laterals from a well penetrate
Off Reservation Parcels[a, d]	5.8406	4.4257	0	85	Number of off reservation private parcels that all laterals from a well penetrate
Fee Parcels[a, c]	0.5418	1.7667	0	28	Number of fee simple parcels that all laterals from a well penetrate
Allotted Parcels[a, c]	0.6453	1.9430	0	15	Number of allotted trust parcels that all laterals from a well penetrate
Tribal Parcels[a, c]	0.1960	1.1169	0	16	Number of tribal parcels that all laterals from a well penetrate
Panel B: Lease Data					
Royalty[a]	0.174	0.0240	0	0.333	Royalty rate for lease *i*
Lease Year[a]	2008	2.285	2005	2015	Year in which lease *i* was signed
Lease Date[a]	1,438	829.7	1	3,993	Days since 1/1/05 until lease *i* was signed
No. of parcels[a, b]	20.43	51.79	1	739	Total number of parcels in PLSS section containing lease *i*
St. dev. of parcel size[a, b]	72.60	38.23	2.23e-05	425.7	St. dev. of size of parcels in PLSS section containing lease *i*
Tribal indicator[a, b]	0.00348	0.0589	0	1	=1 if PLSS section containing lease *i* is all tribal tenure, otherwise 0
Fee indicator[a, b]	0.0288	0.167	0	1	=1 if PLSS section containing lease *i* is all fee tenure, otherwise 0
Allotted indicator[a, b]	0.00440	0.0662	0	1	=1 if PLSS section containing lease *i* is all allotted tenure, otherwise 0

Notes: Panel A summarizes data for all horizontal wells in our study area that were drilled between 2005 and May 2015 that we could spatially match the well bores with the lines emanating from the bore. N = 6,571 for all variables. Data sources are: a) North Dakota Oil and Gas Commission website, b) Authors calculations using DrillingInfo.com data on oil production and U.S. Energy Administration Information on oil prices, c) U.S. Bureau of Indian Affairs, d) Real Estate Portal. Panel B summarizes data for 87,244 leases in our study area. The source is a) DrillingInfo.com data and b) author's calculations based on the PLSS section reported by DrillingInfo.com and land tenure variables and ownership data from U.S. Bureau of Indian Affairs and Real Estate Portal.

produce a single observation for leases with matching terms in a given PLSS section.[35] If parcels that are part of the same drilling unit tend to sign leases with matching terms, this creates the potential for an unknown number of missing observations in the dataset. Because of this important caveat, we focus on PLSS sections composed of a single tenure regime. This allows us to definitely infer that a lease observation pertains to a certain tenure type (e.g., fee simple, allotted trust, and tribal), and hence estimate clean correlations between tenure type and lease characteristics. We can also isolate the first lease signed in each section. This is, in our opinion, the limit of what can be learned about lease timing and royalty rates, given the data structure.

Table 2 Panel B shows summary statistics. Lease rates averaged 17.4 percent with a maximum of 33 percent. The average number of days elapsed since Jan. 1 2005 until leases were recorded is 1438. This is about 2.4 years earlier than the average time elapsed before wells were drilled, which is 2314 days. We emphasize that not all leases have been executed: some sections have had leases expire, and some projects under lease have not been drilled.

VI. Empirical Estimates

Our ultimate goal is to quantify anticommons effects on the expected compensation, or rent, earned by shale parcel owners. We begin by estimating the probability that a parcel has been penetrated by a horizontal well. This is our best proxy for whether or not a parcel owner has been compensated as discussed above. We also estimate revenue from the well, conditional on drilling, along with royalty rates, conditional on leasing. From these pieces of evidence, we estimate the impacts of subdivision and tenure on expected rent from the boom.

A. Drilling Probability

We estimate the probability that parcel *i* was drilled during the boom using the following linear-probability model

$$(8)\quad \begin{aligned} Line_{ij} &= \alpha_j + \phi Acre_{ij} + \mu Longside_{ij} + \delta StD.Neigh_{ij} + \lambda_F Fee_{ij} + \lambda_A ATrust_{ij} + \lambda_T Trib_{ij} + \\ &\beta_O OffNeigh_{ij} + \beta_F FeeNeigh_{ij} + \beta_A ATrustNeigh_{ij} + \beta_T TribNeigh_{ij} + \rho XtraReg_{ij} + \gamma X_{ij} + \varepsilon_{ij}. \end{aligned}$$

[35] According to DrillingInfo's "Lease FAQ" page in their Online Manual: "Drillinginfo does not collect counterparts covering the same tract with the same leasing terms. For example, the minerals in one tract may be owned by 10 people. All 10 people signed individual leases about the same time for the same royalty interest and primary term. Our gatherers will collect the first lease but not the nine remaining counterparts." See http://help.drillinginfo.com/robohelp/robohelp/server/DI_Main/projects/Drillinginfo Online Manual/MyNewProject.htm.

The dependent variable is the indicator for whether or not the parcel was penetrated during the fracking boom. Here i = parcel, j = oil field, the notation α_j represents the 203 oil field fixed effects, and the notation X_{ij} indicates the covariates. To support causal interpretations of the coefficients in the model, we rely on the exogeneity of parcel size, shape, and tenure, conditional on the covariates and oil field fixed effects (see appendix).[36]

The model estimates the effects of parcel and neighborhood characteristics. First consider the parcel-characteristic estimates of ϕ and μ. We expect $\phi > 0$ and $\mu > 0$. In words, we expect higher probabilities of drilling through large, rectangular parcels because oil companies can limit the number of contracting parties (N) by focusing on these parcels. We anticipate $\delta < 0$ if more heterogeneity in parcel sizes raises the costs of negotiating leases with heterogeneous resource owners.[37]

To test for different subdivision effects across tenure types, we include four separate variables that decompose the Number of Neighbors variable into each tenure type: off reservation neighbors, fee neighbors, allotted trust neighbors, and tribal neighbors. We also include three separate indicator variables, one for each tenure type.

The estimates of β_O, β_F, β_A, and β_T provide key anticommons tests. We expect $\beta_T > \beta_O \geq \beta_F > \beta_A$ and we also expect $\beta_{-T} < 0$ for each of the non-tribal tenure types. In words, more finely subdividing a radius around a parcel into any form of private ownership will reduce the probability of drilling. We also predict the effect of subdivision will depend on tenure type. The negative effect on drilling probabilities will be smallest for subdivision off the reservation, followed by fee simple, followed by allotted trust as discussed above in the context of figure 2. The key issue here is that subdivision into different tenure types has different effects on N, the number of excluders to a drilling project.

We also expect $\rho < 0$, meaning that extra tenure regimes should reduce drilling probabilities. Contracting across tenure types – e.g., fee and tribal – could raise transaction costs relative to contracting within regime types because it adds fixed learning costs; for example to research the rules governing fracking under the Bureau of Indian Affairs and the tribal government (see Regan and Anderson 2014).

[36] We include oil field fixed effects because our appendix analysis indicates that shale ownership is more plausibly exogenous to shale quality within rather than across oil fields. However, we show results with and without oil field fixed effects and they are generally similar.

[37] In her studies of common pool resource use, Ostrom (1990) argues that heterogeneity in resource users raises the transaction costs of agreements.

The λ_F, λ_A, and λ_T coefficients measure the extent to which the tenure of parcel *i* influences drilling probabilities, conditional on the degree of neighborhood subdivision and the tenure compositions of neighbors. In this set of estimates, for which the dependent variable measures the probability of being penetrated by a lateral, the λ coefficients are of secondary interest. If the tenure of parcel *i* changes total contracting costs by a small amount, conditional on the composition of neighbors, then we expect $\lambda \approx 0$ for all tenure types.

The results in Table 3 show significant relationships between drilling probability and parcel acres, longside, number of neighbors, and the standard deviation of neighbors that are consistent with anticommons theory. The coefficients are relatively insensitive to the inclusion or omission of different covariates and to oil field fixed effects, but our preferred estimates are in column 4. This model holds constant time-invariant unobservables that may vary across oil fields.

The column 4 coefficient of 0.0016 on parcel acres implies that a one standard deviation increase above the mean (i.e., from 79 to 177 acres) is associated with a 0.159 percent increase in drilling probability. This is a 39 percent increase relative to the mean drilling probability of 0.41. The longside coefficient of 0.203 means a standard deviation increase implies a 0.07 increase in drilling probability, which is a 17 percent increase relative to the mean. The point estimates are $\hat{\beta}_T = 0.0016 > \hat{\beta}_F = -0.0016 > \hat{\beta}_A = -0.0033$. This ordering follows anticommons predictions, and the differences between coefficients are statistically significant. Adding an allotted trust neighbor reduces drilling probabilities by twice as much as the effect of adding a fee neighbor. Adding a tribal neighbor does not affect drilling probabilities, because the $\hat{\beta}_T$ coefficient is statistically insignificant. The coefficient $\beta_O = -0.0018 < \beta_F = -0.0016$ runs counter to our reasoning that the neighbor effect should be smaller off reservation, due to forced pooling. These coefficients are not statistically different from each other, however, and they are sensitive to the inclusion of parcels within cities in the sample.[38]

With respect to the Extra Tenure Regimes variable, we find evidence that a tenure mosaic immediately adjacent to a parcel has discouraged drilling through that parcel. The column 4 point estimate of $\hat{\rho}$ = -0.026 indicates that adding one extra tenure regime decreases the probability that a shale owner has been compensated for his shale (i.e., by hosting a lateral) by 6.5 percent.

[38] When we omit parcels that fall within city boundaries, the relationship flips so that another fee neighbor on the reservation is associated with a greater decline in drilling probability, as expected (see appendix table A2).

Table 3: Parcel Level Estimates of the Probability of a Lateral

	Y = Lateral Indicator			
	(1)	(2)	(3)	(4)
Parcel Variables				
Parcel acres	0.00155***	0.00149***	0.00154***	0.00163***
	(0.000132)	(0.000136)	(0.000135)	(0.000156)
Parcel longside	0.211***	0.203***	0.214***	0.203***
	(0.0296)	(0.0278)	(0.0289)	(0.0294)
Fee parcel indicator	-0.0787*	-0.0934**	0.0160	0.00781
	(0.0437)	(0.0451)	(0.0508)	(0.0521)
Allotted trust parcel indicator	-0.00512	-0.0219	0.0565	0.0286
	(0.0446)	(0.0468)	(0.0463)	(0.0539)
Tribal parcel indicator	-0.0223	-0.0473	0.00964	-0.00777
	(0.0539)	(0.0571)	(0.0513)	(0.0560)
Neighbor Variables				
St. dev. of neighbor size	-0.00568***	-0.00646***	-0.00566***	-0.00609***
	(0.00216)	(0.00224)	(0.00193)	(0.00202)
No. of tenure regimes	-0.0274**	-0.0260**	-0.0243**	-0.0266***
	(0.0115)	(0.0117)	(0.0103)	(0.00987)
Off reservation neighbors	-0.000114	-0.000951**	-0.00116***	-0.00179***
	(0.0000872)	(0.000425)	(0.000382)	(0.000373)
Fee neighbors	-0.000425***	-0.00109***	-0.00122***	-0.00164***
	(0.0000759)	(0.000344)	(0.000302)	(0.000293)
Allotted trust neighbors	-0.00172**	-0.00189**	-0.00190**	-0.00334***
	(0.000762)	(0.000874)	(0.000788)	(0.000868)
Tribal neighbors	-0.000425	-0.0000594	0.00136	0.00165
	(0.00123)	(0.00114)	(0.00107)	(0.00112)
Covariates				
Thickness-to-depth ratio	26.90***	25.25***	42.81***	34.61***
Feet to water (000s)	-0.00998***	-0.0100***	-0.00563***	-0.0118***
No. Neighbors underwater	-0.00392***	-0.00417***	-0.00401***	-0.00575***
Topographic roughness	-0.000343*	-0.000335**	-0.000382**	-0.000241*
City indicator		-0.0413	-0.00439	-0.0533
Feet to railroad (000s)		-0.00125	-0.000355	-0.00498*
Road density in radius		0.000011**	0.000012***	0.000021***
x coordinate (000s)			-0.00276***	
y coordinate (000s)			-0.000569	
Oil field fixed effects	No	No	No	Yes
Adjusted R-squared	0.241	0.243	0.259	0.312
Observations	27,656	27,656	27,656	27,656

Notes: Standard errors are clustered by oil field and shown in parentheses. * p<0.1, ** p<0.05, *** p<0.01. A parcel's neighborhood includes all parcels touching a one-mile radius from the parcel's boundary. All specifications control for the slight variation in the total area of the one mile radius, due to variation in the size of parcels on the exterior of the radius.

The signs on the other coefficients in Table 3 are mostly as expected. Parcels with greater thickness-to-depth ratios were more likely to be drilled as were parcels in areas with greater road infrastructure. Parcels close to water were less likely to be drilled, as were parcels within city boundaries. These findings make sense because regulatory rules sometimes dissuade oil drilling in urban areas and in areas near bodies of water.

To summarize the results in table 3, parcel owners were less likely to be compensated for their shale with increases in the number of exclusion rights holders in the surrounding one-mile radius. We interpret the economic significance of the results below, in Section VII. The probability of compensation is especially sensitive to the number of allotted trust parcels and, to a lesser extent, with the number of fee parcels in the radius. By contrast, we find no evidence that drilling probabilities decrease with an increase in the number of tribal parcels in the radius. Table A2 in the appendix shows the results are robust to subsamples that omit parcels in cities or parcels that have neighboring parcels in cities, and to the use of the full sample that includes federal and state government parcels. Table A3 indicates that our main inferences are also robust to the use of a model that allows for arbitrary spatial correlation in the error structures following Conley (2008) and Hsiang (2010). Table A4 tests for the effects of subdivision and tenure on the extent to which a parcel has been drilled, measured by the length of laterals penetrating a parcel.[39] There we find the same pattern of results as in table 3: an increase in the number of neighbors in the 1-mile radius is associated with decreases in line miles, unless the neighbor's tenure is tribal.

Finally, in table A5 of the appendix we estimate the effects of subdivision and tenure on whether or not parcel *i* has a well bore. Recall that a bore is the vertical portion of a horizontal well, and 7.9 percent of the sample parcels have a bore. It's placement on a particular parcel may be important because the surface owner of that parcel is positioned to benefit financially for allowing well-pad infrastructure to be housed on her land. Using the same model as equation (8), we find evidence that oil companies prefer to locate on-reservation well bores on fee and not tribal land, presumably because negotiating a surface access contract with the tribe entails a higher transaction cost when compared with the cost of negotiating with a private surface owner. This result is consistent with the logic of figure 2, which suggests that transaction costs of contracting are lower when dealing with a single private entity rather than a government entity.

B. Timing of Drilling and Leasing

We now consider the effects of tenure and subdivision on the timing of drilling and leasing, conditional on both occurring. The theory in section III implies that high-*N* drilling projects will occur later in time than low-*N* drilling projects. The theory also implies that leasing will occur later in time in areas in which the transaction costs of leasing are high.

[39] This outcome variable is important because a parcel's shale can often be drilled multiple times, enabling parcel-owner compensation from multiple drilling projects.

To assess the relationship between the timing of drilling and subdivision and tenure, we employ the well-level data summarized in table 2. In these tests, we measure *N* based on the drilling path actually observed, rather than equally weighting all of the drilling paths that might be taken as in our one-mile radius variables used to test for the probability of a lateral.

Using the well-level data, we estimate the following empirical model

$$(9)\quad \begin{aligned} Days_{wj} &= \alpha_j + \lambda_F Fee_{wj} + \lambda_A ATrust_{wj} + \lambda_T Trib_{wj} + \beta_O OffParc_{wj} + \beta_F FeeParc_{wj} \\ &+ \beta_A ATrustParc_{wj} + \beta_T TribParc_{wj} + \rho Regimes_{wj} + \gamma X_{wj} + \psi Linemiles_{wj} + \varepsilon_{wj} \end{aligned}$$

The dependent variable is the number of days elapsed from the start of the boom until the well was drilled. Here *w* = the 6,537 wells, *j* = oil fields, the notation α_j represents the 203 oil-field fixed effects, and the notation X_{ij} indicates the covariates, measured at the parcel containing the well bore.

Table 4 presents results. We focus on column 3, which includes oil field fixed effects. In that column, $\hat{\lambda}_T$, $\hat{\lambda}_F$ and $\hat{\lambda}_A$ are all positive, meaning that having a vertical bore on reservation land is associated with a delay, relative to wells with bores off the reservation. The estimates of $\hat{\lambda}_T$ are largest, which is consistent with the transaction costs of surface access being highest for well pads on tribal land as in figure 2.

With respect to the $\hat{\beta}$ coefficients, the main patterns are $\hat{\beta}_A > \hat{\beta}_F > \hat{\beta}_T$ and $\hat{\beta}_T = 0$ as expected, although differences are not always statistically significant. The column 3 point estimate of $\hat{\beta}_A$=36.29, for example, means that drilling delays increased by 36.3 days for each allotted parcel penetrated by a well and $\hat{\beta}_F$=21.09 indicates the increase is 21.1 days for each fee simple parcel. By contrast, $\hat{\beta}_T$ is statistically insignificant in all specifications, which means that penetrating an additional tribal parcel is not associated with longer delays. These results are consistent with theoretical reasoning, in that they imply that longer delays are associated with projects involving a greater number of exclusion rights.

To assess the relationship between lease timing and transaction costs, we employ the lease data from DrillingInfo.com and estimate the following equation

$$(10)\quad Lease_{lsjt} = \alpha_j + \phi_t + No.Parc_{sj} + St.Dev_{sj} + \omega_F Fee_{sj} + \omega_A ATrust_{sj} + \omega_T Trib_{sj} + \gamma X_{sj} + \varepsilon_{sj}.$$

The dependent variable is the number of days elapsed between Jan. 1 2005 and lease signing. Here *l* = the 87,244 lease observations, *s* = the PLSS section, *j* = oil fields, the notation α_j represents oil-field fixed effects and ϕ_t represents year fixed effects, which we include in

some specifications. The notation X_{sj} indicates the covariates, averaged at the section level. The tenure and number of parcel variables are defined in Table 2.

Table 4: Well-Level Estimates of Days Elapsed before Drilling

	(1)	(2)	(3)
Location of Well Bore			
Fee	0.936	200.0**	300.1***
	(101.2)	(94.45)	(84.87)
Allotted Trust	23.16	220.3**	290.7***
	(82.39)	(89.50)	(88.00)
Tribal Trust	57.55	274.0	337.1
	(235.0)	(257.3)	(228.6)
No. of Parcels Cut by Lines			
Tenure Regimes	73.31	92.95*	82.06
	(49.88)	(47.91)	(56.95)
Off Res. Parcels	22.69***	16.23***	14.08***
	(4.695)	(4.251)	(2.937)
Fee parcels	14.77**	21.74***	21.09***
	(6.289)	(7.840)	(8.036)
Allotted parcels	48.52***	43.54***	36.29***
	(10.69)	(9.218)	(9.962)
Tribal parcels	11.21	19.20	17.01
	(18.09)	(18.79)	(17.62)
Controls			
Geographic & Economic	Yes	Yes	Yes
Coordinates	No	Yes	No
Oil Field Fixed Effects	No	No	Yes
Observations	6537	6537	6537
Adjusted R-squared	0.046	0.094	0.233

Notes: standard errors are clustered by oil field. * p<0.1, ** p<0.05, *** p<0.01. The regressions include all horizontal oil wells for which we could identify the completion date. The tenure variables represent the total number of parcels from each tenure type through which lines from a single horizontal well project penetrate. Covariates are measured at the well-bore.

Table 5 shows the estimates. First, there is a positive relationship between the number of parcels in a section and lease date, meaning that areas with more parcels (and presumably higher transaction costs) are put under lease later in time. Second, tenure is strongly related to lease timing. The omitted category is an off-reservation lease. Focusing on our preferred specifications, with oil field fixed effects, the results imply the following ordering of leasing: 1) off reservation leases, 2) fee simple leases, 3) allotted trust leases, and 4) tribal leases. These results are informed by figure 2, which explains why the transaction costs of leasing may be highest for tribal leases, after controlling for the number of parcels in a section. The results in table 5 also provide an interesting contrast to those in table 4. When considered together, the results suggest the time between lease and drilling is shortest for tribal projects.

This result is likely explained by the lower royalty rates in tribal leases, as explained below. Whereas high transaction costs plausibly caused later lease times, the lower royalty rates would motivate a short lease-to-drill time, which is what the findings imply.

Table 5: Lease Level Estimates of Time Elapsed before Leasing

	Y= Lease Year		*Y= Days since 1/1/2005*	
	(1)	(2)	(3)	(4)
Number of parcels	0.00295***	0.00255***	1.109***	0.986***
	(0.000882)	(0.000697)	(0.301)	(0.245)
Std. dev. of parcel size	0.00772***	0.00529***	2.749***	1.825***
	(0.00129)	(0.00139)	(0.469)	(0.509)
Fee indicator	-0.699***	0.607**	-229.2**	233.2***
	(0.258)	(0.238)	(96.65)	(89.55)
Tribal indicator	3.708***	4.698***	1315.0***	1666.0***
	(0.473)	(1.376)	(159.4)	(472.5)
Allotted indicator	0.432	2.496**	159.8	889.2**
	(0.327)	(1.064)	(112.0)	(362.8)
Constant	2006.8***	2008.7***	842.2***	1408.0***
	(0.185)	(0.377)	(67.36)	(137.4)
Controls	-65.41***	43.26	-23359.2***	11189.9
Geographic & Economic	0.000006**	0.000002	0.00258**	0.00161
Oil Field Fixed Effects	No	Yes	No	Yes
Observations	87244	87244	87244	87244
adj. R^2	0.048	0.179	0.048	0.179

Notes: Standard errors in parentheses, clustered by oil field. This regression is restricted to PLSS sections composed of only a single tenure type. This provides an aggregated measure of the effect of subdividing a section into additional parcels of a given tenure type. * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

C. Project Revenues and Royalty Rates

We now consider how tenure and subdivision affected compensation earned by shale owners during the boom. The section III theory implies that compensation could increase with '*N*' through two related channels. First, higher oil prices may be required to trigger drilling in areas where transaction costs of leasing are high. Second, requested royalty rates may increase with *N*, the number of parties in a lease.

We first estimate a version of equation 9 using the well-level data set to assess how *N* is related to project revenue. Here the dependent variable is the log of revenue from each well during its first 18 months of production. Table 6 shows results. Focusing on columns 3 and 6, which include oil field effects, we note that wells penetrating multiple tenure regimes, and more allotted trust parcels, earned higher revenue. These 'high *N*' projects were perhaps not profitable in the early phases of the boom and hence were not drilled until oil prices and

drilling technologies improved. In addition, the projects may have inadvertently benefited from favorable oil prices during the first 18 months after drilling. In either case, the results imply that owner rents from drilling may have increased with *N*, conditional on drilling.[40] We interpret the economic significance of the results below, in Section VII.

Table 6: Well-Level Estimates of Revenue from Well over First 18 Months

	Y = ln(Revenue 3% DR)			Y = ln(Revenue 5% DR)		
	(1)	(2)	(3)	(4)	(5)	(6)
Location of Well Bore						
Fee	0.151	0.0519	-0.0718	0.160	0.0511	-0.0676
	(0.104)	(0.130)	(0.249)	(0.101)	(0.128)	(0.252)
Allotted Trust	0.183**	0.0896	0.0224	0.185**	0.0829	0.0240
	(0.0723)	(0.0838)	(0.208)	(0.0720)	(0.0842)	(0.213)
Tribal Trust	0.371*	0.257	0.239	0.378*	0.253	0.244
	(0.208)	(0.229)	(0.328)	(0.216)	(0.238)	(0.338)
No. of Parcels Cut by Lines						
Tenure Regimes	0.115***	0.107***	0.0939**	0.114***	0.105***	0.0938**
	(0.0313)	(0.0320)	(0.0453)	(0.0321)	(0.0327)	(0.0471)
Off Res. Parcels	0.00793*	0.0135***	0.0106**	0.00642	0.0124***	0.00978**
	(0.00432)	(0.00382)	(0.00420)	(0.00446)	(0.00378)	(0.00419)
Fee parcels	-0.00263	-0.00626	-0.00477	-0.00474	-0.00871	-0.00754
	(0.00985)	(0.00931)	(0.00643)	(0.00914)	(0.00868)	(0.00565)
Allotted parcels	0.0169**	0.0200**	0.0308***	0.0152*	0.0186**	0.0297***
	(0.00780)	(0.00859)	(0.0107)	(0.00773)	(0.00848)	(0.0108)
Tribal parcels	0.00614	0.00496	0.0106	0.00532	0.00378	0.00942
	(0.0125)	(0.0136)	(0.0130)	(0.0127)	(0.0140)	(0.0133)
Controls						
Geographic & Economic	Yes	Yes	Yes	Yes	Yes	Yes
Coordinates	No	Yes	No	No	Yes	No
Field Effects	No	No	Yes	No	No	Yes
Observations	6376	6376	6376	6376	6376	6376
Adjusted R-squared	0.090	0.121	0.227	0.084	0.120	0.221

Notes: standard errors are clustered by oil field. * p<0.1, ** p<0.05, *** p<0.01. The regressions include all horizontal oil wells for which we could identify the completion date. The tenure variables represent the total number of parcels from each tenure type through which lines from a single horizontal well project penetrate. Covariates are measured at the well-bore.

Finally, we estimate the relationship between tenure and project-level royalty rates, *R*. Our theory suggests that *R* should rise with *N* if we assume that transaction costs are sunk at the time of negotiation (see section III). The higher royalty rate is potentially a key mechanism to explain why areas dominated by allotted trust parcels have lower drilling probabilities and longer delays than areas dominated by fee and tribal holdings. In particular,

[40] Revenues also increased with the number of off-reservation parcels penetrated by the well but did not increase with the number of fee simple parcels. Other results, not shown here, indicate this is due to the late timing of a handful of projects through fee parcels that had long lags between drilling and well completion.

a relationship of $R_A > R_F > R_T$ would be consistent with anticommons theory, where R_A is the average royalty rate requested by allotted owners, R_F is the average rate requested by fee owners, and R_T is the average rate requested by the tribe.

To assess the relationship between N and royalty rates we employ the lease data from DrillingInfo.com using the same regression model as in equation 10, but here the dependent variable is the logged royalty rate.[41] Table 7 shows results.

Table 7: Estimates of Royalty Rates Contained in Leases

	(1)	(2)	(3)	(4)
	Y=ln(lease rate in section i in year t)			
No. of parcels	0.0000110	-0.0000311	0.0000813**	0.0000334
	(0.0000285)	(0.0000229)	(0.0000408)	(0.0000291)
St. dev. of parcel size	-0.0000992**	-0.000133***	0.0000727*	-0.00000465
	(0.0000391)	(0.0000286)	(0.0000389)	(0.0000393)
Fee indicator	-0.0335***	-0.0297***	-0.0538***	-0.0168
	(0.00559)	(0.0107)	(0.00872)	(0.0131)
Tribal indicator	-0.0738***	-0.0958***	-0.0117	-0.00662
	(0.0237)	(0.0264)	(0.0211)	(0.0336)
Allotted indicator	0.0139	0.0178	0.0274**	0.0696***
	(0.0107)	(0.0130)	(0.0110)	(0.0198)
Constant	-1.803***	-1.803***	-1.747***	-1.691***
	(0.00679)	(0.0140)	(0.00722)	(0.0160)
Year Indicators				
2006	0.0212***	0.0223***		
2007	0.0663***	0.0686***		
2008	0.0919***	0.0995***		
2009	0.0949***	0.101***		
2010	0.158***	0.161***		
2011	0.168***	0.182***		
2012	0.186***	0.191***		
2013	0.167***	0.176***		
2014	0.191***	0.195***		
2015	0.149***	0.154***		
Controls				
Geographic & Economic	Yes	Yes	Yes	Yes
Oil Field Fixed Effects	No	Yes	No	Yes
adj. R^2	0.268	0.330	0.026	0.101
N	86684	86684	86686	86686

Notes: Standard errors in parentheses, clustered by oil field. This regression is restricted to leases in PLSS sections composed of only a single tenure type. This provides an aggregated measure of the effect of subdividing a section into additional parcels of a given tenure type. * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

The key finding is the ordering of the point-estimate coefficients, which is $\omega_A > \omega_F > \omega_T$ in columns 1 and 2, which include year fixed effects. This ordering is consistent with the theoretical framework if transaction costs are sunk (see section III). The omitted category is an off-reservation lease, so the average royalty rates are relative to off reservation

[41] We employ a variety of different estimate strategies to assess the robustness of these results. We calculate average lease rates for each section-year cell and find similar results at the section level. We also calculate an area-weighted average lease rate at the section level which gives more weight to leases associated with larger acreage that are more likely to be associated with multiple parcels—the results are unchanged.

rates. Based on column 2, royalty rates requested in tribal leases were about 9.6 percent lower than off reservation leases. This is perhaps evidence that the tribal government prioritized promoting oil development at the expense of getting the best price; this has happened in other settings, such as the case of forest sales approved by local governments in Indonesia (see Burgess et al. 2012).

The column 3-4 regression results that do not control for year fixed effects are also of interest because the timing of leases is endogenous to transaction costs (see table 5), and because royalty rates trended up during 2005-2015. Excluding year effects, our preferred reduced form estimates of the effects of tenure on royalty rates in column 4 reveal a silver lining of transaction-cost induced leasing delays. For leases that were signed later in time, such as those on allotted land, requested royalty rates are higher because of the delay.

VII. Discussion: Economic Significance and Qualifications

A. Back-of-the-Envelope Calculations

We combine the collection of results just described in order estimate the net effect of allotment on expected rents from the boom. For a policy thought experiment, we image how expected compensation would have changed if the tribe held full mineral ownership at the boom's onset. Taking the natural log of the landowner's expected payout and differentiating with respect to *N* allows us to decompose the effect of *N* on expected payout as:

$$\%\Delta E(Payout) = \%\Delta \Pr(Well) + \%\Delta Revenue + \%\Delta Royalty$$

If all allotted and fee parcels were converted to tribal, the probability of a well would increase by 0.0033 per allotted parcel and 0.0016 per fee parcel, based on the column 4 coefficients in table 3.[42] Outside of cities, the average reservation parcel had 27.8 allotted trust neighbors and 18.5 fee neighbors. Hence, the probability would increase by 27.8 x 0.00334 + 18.5 x 0.00164 = 0.123 percentage points. This is a 29.3 percent increase relative to the mean drilling probability of 0.42 on the reservation, outside of cities. Converting ownership from allotted and fee to tribal would also eliminate extra regimes, which has a mean of 0.62 for rural reservation parcels. This would increase drilling probability by 0.62 x 0.026 = 0.0161 percentage points, or an additional 3.8 percent relative to the mean.

Conditional on drilling, if wells penetrated tribal parcels instead of allotted, the revenue for each parcel penetrated would decrease by 3.08 percent, based on the column 3 coefficient from table 6. Outside of cities, the average well on the reservation penetrated 3.24

[42] For this and other back-of-the-envelope calculations, we focus only on coefficients that are statistically different from zero. This leads to conservative estimates of the beneficial effects of tribal ownership.

allotted parcels. Hence, the revenue, conditional on drilling, would decrease by 3.24 x 3.08 = 10.0%. Moreover, changing all ownership to tribal would eliminate any extra regime crossing, which has a mean of 0.45 for wells on the reservation. Hence, well revenue would fall by an extra 9.4% x 0.045 = 4.2%, based on the table 6, column 3 coefficient. Whereas extra tenure regimes and allotted trust tenure reduced the probability of drilling, the silver lining for shale owners is that project revenues were higher on delayed projects due to these tenure characteristics.

Replacing allotted tenure with tribal tenure would increase requested royalty rates by about 6.96% for each PLSS lease area converted to tribal, based on table 7 column 4 estimates. On the reservation outside of cities, about 0.38 of the sections are dominated by allotted parcels. Hence, replacing the allotted parcels would reduce requested royalty requests by about 6.96% x 0.38 = 2.64%. This is an upper bound estimate of actual compensation, because some leases with high requested royalty rates are on projects not drilled.

Table 8 combines these results to construct rough, back-of-the-envelope calculations. At the parcel level, tribal ownership would have increased the probability of compensation - a lateral - by 33.3%. Conditional on a well being drilled, conversion to tribal ownership would have decreased revenue during the first 18 months by 14.2%. Assuming the projects paid the mean royalty rates requested in leases, converting to tribal ownership would have reduced royalty payments by 2.63%. The net effect on expected compensation is large and positive: a 16.4% increase despite the lower revenue and royalty rates.

Panel B monetizes the effects. We begin by estimating the per-parcel change in expected rents in three steps. First, we calculate the royalty payments from an average well over the first 18 months, discounted at 3 percent annually. This is $10.3 million in revenue, multiplied by the 0.174 average royalty rate, yielding $1.79 million. Second, we divide this amount by the average number of reservation parcels in a 1280 acre oil drilling unit, which is 20.5. The resulting average royalty payment per parcel is $87,314. Third, we multiply $87,314 by 0.164 - the increase in expected compensation - yielding $14,344. To scale this figure up to the reservation level, we multiply $14,344 by the number of reservation parcels within oil fields, and outside of cities, yielding $123.5 million. To generate a per-capita amount of $19,483, we divide by the 2010 Ft. Berthold Indian reservation population, which was 6,341 according to the U.S. census. For perspective, the 2010 per-capita income for American Indians on Ft. Berthold was $13,543. Hence, the loss in expected rent from allotment, subdivision, and fractionation of $19,483 exceeded per capita income.

Table 8: Increase in Expected Rents if Shale was Owned by the Tribe

	Convert to Tribal Ownership
Panel A: Percentage Changes, Per Parcel	
%Δ in Prob. of Compensation	33.3%
%Δ in 1st 18 month Well Revenue	-14.2%
%Δ in Royalty Rate	-2.63%
%Δ in Expected Compensation	16.4%
Panel B: Compensation Changes	
Per-Parcel Δ in Exp. Compensation, 1st 18 months	$14,344
Total Δ in Exp. Compensation, 1st 18 months	$123.5 million
Per-Capita Δ in Exp. Compensation, 1st 18 months	$19,483

Notes: The calculations in the first row are based on coefficient estimates in column 4 of table 3. The calculations in the second row are based on coefficient estimates in column 3 of table 6. The royalty rate calculations are based on coefficient estimates in column 4 of table 7. We estimate the per-parcel change in expected rents in three steps. First, we calculate the royalty payments from an average well over the first 18 months, discounted at 3 percent annually. This is $10.3 million in revenue, multiplied by the 0.174 average royalty rate, yielding $1.79 million. Second, we divide this amount by the average number of reservation parcels in a 1280 acre oil drilling unit, which is 20.5. The resulting average royalty payment per parcel is $87,314. Third, we multiply $87,314 by 0.164 - the increase in expected compensation from a conversion to tribal ownership - yielding $14,344. To scale this figure up to the reservation level, we multiply $14,344 by the number of reservation parcels within oil fields, and outside of cities, yielding $123.5 million. To generate a per-capita amount of $19,483, we divide by the 2010 Ft. Berthold Indian reservation population, which was 6,341 according to the U.S. census.

There are reasons why the calculations in table 8 might overstate or understate actual foregone rents. The simulations might understate foregone rents because they focus on only the first 18 months of royalty payments. Estimates of oil decline curves from Hughes (2012) suggest that only 60 percent of oil from a typical Bakken well will be extracted within the first 18 months. The estimates might overstate foregone rents if oil drilling through subdivided and fractionated tenure quickly resumes after our time of writing, which is May 2017. New technologies may make drilling more profitable, meaning that royalty payments to some shale owners were simply delayed. If this is true, the costs of delay will largely depend on time discounting and future oil prices. At present, we note that excessive supply of oil from horizontal fracking has driven down world prices, which suggests that benefits of delay, if positive, will likely require large improvements in the technology of extracting more oil from a fixed amount of shale. Finally, as noted in the introduction, fracking may cause local environmental and social harms, suggesting the benefits of more aggressive drilling may be overstated. We emphasize that on the Fort Berthold reservation and elsewhere, residents were exposed to local drilling disamenities whether or not they were compensated for shale.

B. Alternative Interpretations, Caveats, and Generalizations

We focus on anticommons mechanisms through which subdivision delays drilling, but alternative causal channels are possible. We do not control for cultural differences and

preferences across owners. If the average Native American owner of allotted trust on Ft. Berthold is more resistant to drilling than the average non-Native fee simple owner, for cultural reasons, then differences in preferences might explain lower probabilities associated with allotted trust. A test for this alternative could compare drilling uptake on fee parcels with uptake on allotted trust parcels with only a single owner, but we lack data on parcel-specific allotted trust ownership numbers. In any case, an explanation focused on preferences rather than contracting is difficult to reconcile with the observation that the tribal government on Fort Berthold – which is democratically elected - has aggressively pursued drilling. Even if differences in the probability of drilling on fee simple versus allotted trust parcels reflected cultural preferences, preferences would not explain differences in drilling through allotted trust versus tribal parcels.

A second potential issue is that, if smaller parcels have higher surface quality, conditional on oil field fixed effects, and drilling through shale damages surfaces, then our estimates might be capturing systematic resistance from small-parcel owners due to environmental damage concerns. We do not think this alternative mechanism is driving the results for two reasons. First, environmental damages from shale drilling – whether perceived or real - spill across neighboring parcels and are not generally contained to surface areas above a particular section of drilling line (see, e.g., Olmstead et al. 2013, Muehlenbachs et al. 2015). This implies an owner of a small parcel cannot prevent exposure to external effects from drilling simply by trying to prevent drilling beneath his parcel. On the contrary, coordination challenges from subdivision can actually inhibit neighbors from preventing oil drilling at a scale large enough to eliminate exposure to adverse effects. This argument is similar to Hansen and Libecap (2004), who explain how high contracting costs among small landowners exacerbated environmental pollution during the U.S. dust bowl era. The argument is also consistent with the observation that some tribes – for example the Turtle Mountain Band of Chippewa in North Dakota – banned fracking entirely within reservation boundaries. This policy would likely not be possible for reservations with several private parcels.[43]

Finally, our study might be criticized on the grounds that the findings narrowly apply to the Fort Berthold reservation, and to the peculiar institution of allotted trust tenure. While we agree that allotted tenure is peculiar (and apparently quite ineffective), our results also demonstrate advantages of tribal government over standard, fee simple ownership of small private parcels. While a fuller investigation of other settings is outside the scope of our study,

[43] For details on the fracking ban, see www.huffingtonpost.com/sarah-van-gelder/in-north-dakotas-booming_b_9078378.html.

we think the anticommons logic should apply to other comparisons of government versus subdivided private land. Evidence that it does is found in table A6 of the appendix, which shows that patterns of drilling on and around federal BLM and North Dakota state land resemble patterns on and around tribal land. We do speculate, however, that the potential scale advantages of government ownership, whether tribal, state, or federal, is conditioned by the quality and transparency of governance.[44]

VIII. Conclusions

Land privatization programs are appealing to economists because most agree there are stronger incentives to invest in individually owned land when compared to communal land. Where privatization programs have been implemented, they have generally induced investment, particularly with respect to agricultural production and household quality (see Galiani and Schargrodsky 2012). In the specific case of North American indigenous lands, there is also evidence that movement towards privatization has improved parcel-specific surface investments (Anderson and Lueck 1992, Akee 2009) and improved overall measures of Native population incomes (Aragón 2015).

We examine a qualification to the benefits of privatization. Creating more exclusion rights through the subdivision of communal land can frustrate the efficient use of natural resources that span multiple parcels and cannot be profitably exploited without the consent of all (or most) owners. The problem is that subdivision raises contracting and coordination costs and may lead to the underutilization of large-scale resources, such as wind and shale oil.[45] In the setting we study – oil extraction from the Fort Berthold Indian reservation and surrounding lands - we find that having more subdivided and private neighboring parcels reduced expected rents from ownership. In general, we find that drilling on a parcel is encouraged if the surrounding area is owned by a single entity; in this case, the tribe.

Our findings provide another angle from which to view the allotment of Native American lands that complements other research on the legacy of this era. Accounts written by sociologists, historians, and legal scholars characterize the injustices of allotment by documenting the large transfers of land wealth from Native Americans to non-Indians that resulted (see, e.g., Banner 2005). We join other economists by emphasizing that allotment did

[44] Successful governance of oil extraction, for example, must limit the threat of expropriation (see Bohn and Deacon 2000 and Stroebel and van Benthem 2013).

[45] Our arguments and study are similar to a working paper by Holmes et al. (2015) who study agglomeration economies of density, also in the context of the Bakken. One key difference is that our study focuses to a greater extent on property rights and tenure, exploiting the different systems that exist on Forth Berthold.

much more than transfer resource wealth; it also fundamentally affected resource productivity, both positively and negatively, by creating new systems and mixtures of land tenure. Our contribution is to emphasize, with specific detail, how the subdivision of tribal tenure has derailed the coordinated development of a valuable natural resource. Back-of-the envelop estimates suggest the subdivision of tribal land reduced Fort Berthold per-capita earnings from the fracking boom by an amount exceeding annual per capita income from other sources. Moreover, we expect that subdivided tenure has reduced rents on other Native American lands that harbor large stocks of shale, and hold other spatially expansive resources with value such as wind.

Our findings contribute to a growing literature that seeks to better understand how historical, top-down institutions imposed on indigenous societies have affected modern economic outcomes.[46] Specifically, our results contrast with important research by Anderson and Lueck (1992), who find that, for agricultural productivity, fee simple outperformed allotted trust which outperformed tribal ownership. For shale oil, we find that tribal ownership outperformed fee simple, which outperformed allotted trust. In both cases, the allotted trust regime is strictly dominated, which raises questions about why it persists in spite of its apparent ineffectiveness (see Shoemaker 2003).

The findings are relevant to contemporary policy. On one hand, they suggest that transaction costs of finding resource owners, and plodding through federal administrative procedures, have slowed energy development on Native American lands as suggested elsewhere (Shoemaker 2003, Regan and Anderson 2014). The policy implication is to streamline mineral registry systems and approval processes. This is relevant for a contemporary proposal to privatize indigenous lands in Canada, and supports that proposal's emphasis on developing a clear land titling registry system (Flanagan et al. 2010). On the other hand, the evidence here indicates that privatization can induce land-assembly style coordination failures (Buchanan and Yoon 2000, Heller 2008). Coordination problems are not solved by better administration, and may require a heavier-handed solution. One such solution is to give communal title and clear management authority to indigenous communities. Evidence suggests this has led to effective large-scale resource management in other settings, such as the case of forest conservation in the Peruvian Amazon (Blackman et al. 2017), and forest management among tribes in the U.S. (Krepps and Caves 1994).

[46] This literature includes Brown et al. (2017), Feir (2016), Akee et al. (2015), Dippel (2014), Dimitrova-Grajzl et al. (2014), Cookson (2010), Akee (2009), Anderson and Parker (2008), Cornell and Kalt (2000), Anderson (1995), Anderson and Lueck (1992), Carlson (1981), and Trosper (1978) among others.

Beyond the issue of indigenous resources, we recognize there are drawbacks to government ownership of subsurfaces, and we do not mean to suggest this is a Pareto improving institutional solution to the coordination problem in every setting. One alternative used extensively in the United States is the regulation of horizontal fracturing by state oil and gas commissions, including forced pooling rules that limit the power of individual landowners to holdup development. The findings here suggest that significant contracting problems persist in spite of these rules, at least on the Bakken. In any case, our study raises questions about how new horizontal drilling technologies have changed the optimal ownership of oil, and it provides context to arguments that conventional (vertical) oil and gas drilling is easily delayed on U.S. government land (Kunce et al. 2002, Gerking and Morgan 2007). We hypothesize that government ownership is relatively more beneficial for shale oil, due to the horizontal nature of drilling. These scale advantages of government ownership – which are conditioned by the quality of governance - may affect the future development of shale in countries outside of the U.S., where governments generally own subsurfaces.

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Appendix 1: Comparative Statics

For notational convenience let $\left(pq - \tau N - \underline{c}\right) = \hat{S}$

1. $\frac{\partial R^{N\tau}}{\partial N}$
   a. **When transaction costs are not sunk**

$$R^{N\tau} = \frac{N}{N+1} \times \frac{\left(pq - \tau N - \underline{c}\right)}{pq} = \frac{N}{N+1} \times \frac{\hat{S}}{pq}$$

$$\frac{\partial R^{N\tau}}{\partial N} = \frac{1}{pq(N+1)^2}\left[\hat{S} - \tau N(N+1)\right]$$

This is expression is of ambiguous sign without further assumptions about S, τ, and N because $S > 0$ but $-\tau N(N+1) < 0$. This leave us with

$$\frac{\partial R^{N\tau}}{\partial N}\begin{cases} > 0 & \hat{S} > \tau N(N+1) \\ < 0 & \hat{S} < \tau N(N+1) \end{cases}$$

   b. **When transaction costs are sunk.**

$$R^{N} = \frac{N}{N+1} \times \frac{\left(pq - \underline{c}\right)}{pq}$$

$\frac{\partial R^{N}}{\partial N} = \frac{1}{(N+1)^2} \times \frac{(pq-\underline{c})}{pq} > 0$ for projects with positive expected surplus.

2. **Derivation of $\Pr(Well)$, $\frac{\partial \Pr(Well)}{\partial N}$, and $\frac{\partial \Pr(Well)}{\partial \tau}$**

$$\Pr(Well) = \frac{(1 - R^{N\tau})pq - \tau N - \underline{c}}{\overline{c} - \underline{c}}$$

$$= \frac{1}{\overline{c} - \underline{c}}\left[pq - R^{N\tau}pq - \tau N - \underline{c}\right]$$

$$= \frac{1}{\overline{c} - \underline{c}}\left[\hat{S} - R^{N\tau}pq\right]$$

$$= \frac{1}{\overline{c} - \underline{c}}\left[\hat{S} - pq \times \frac{N}{N+1} \times \frac{\hat{S}}{pq}\right]$$

$$= \frac{1}{\overline{c} - \underline{c}}\left[\hat{S} - \frac{N}{N+1} \times \hat{S}\right]$$

$$= \frac{\hat{S}}{\overline{c} - \underline{c}}\left[1 - \frac{N}{N+1}\right]$$

$$= \frac{\hat{S}}{\overline{c} - \underline{c}}\left[\frac{N+1-N}{N+1}\right]$$

$$= \frac{\hat{S}}{(\overline{c} - \underline{c})(N+1)}$$
$$= \frac{\left(pq - \tau N - \underline{c}\right)}{(\overline{c} - \underline{c})(N+1)}$$

And hence

$$\frac{\partial \Pr(Well_i)}{\partial N} = \frac{1}{(\overline{c}-\underline{c})(N+1)^2}\left[-\hat{S} - \tau(N+1)\right] < 0 \qquad \text{for } \hat{S} > 0.$$
$$\frac{\partial \Pr(Well_i)}{\partial \tau} = \frac{-N}{(\overline{c}-\underline{c})(N+1)} < 0.$$

3. $\boldsymbol{\frac{\partial \mathrm{E}(Payout)}{\partial N}}$

$$E(Payoff_i) = \Pr(Well_i) \times R^{N\tau} \times pq$$

$$\frac{\partial E(Payoff_i)}{\partial N} = pq\left[\frac{\partial \Pr(Well_i)}{\partial N} \times R^{\tau N} + \frac{\partial R^{N\tau}}{\partial N} \times \Pr(Well_i)\right]$$

Putting together all of the pieces:

$$\frac{\partial E(Payoff_i)}{\partial N} = pq\left\{\frac{1}{(\overline{c} - \underline{c})(N+1)^2}\left[-\hat{S} - \tau(N+1)\right] \times \left(\frac{N}{N+1}\right) \times \left(\frac{\hat{S}}{pq}\right) + \frac{1}{pq(N+1)^2}\left[\hat{S} - \tau N(N+1)\right] \times \frac{\hat{S}}{(\overline{c} - \underline{c})(N+1)}\right\}$$

Factor out $\frac{\hat{S}}{pq(\overline{c}-\underline{c})(N+1)^3}$ to get:

$$\frac{\partial E(Payoff_i)}{\partial N} = \frac{\hat{S}}{\left(\overline{c} - \underline{c}\right)(N+1)^3}\left\{N\left[-\hat{S} - \tau(N+1)\right] + \left[\hat{S} - \tau N(N+1)\right]\right\}$$

$$= \frac{\hat{S}}{\left(\overline{c} - \underline{c}\right)(N+1)^3}\left[\hat{S}(1-N) - 2\tau N(N+1)\right] < 0$$

Appendix 2: Timing and Distribution of Allotted Reservations

Figure A1: Timing and Distribution of Allotted Reservations

Notes: This map is based on our digitization of an 1890 Office of Indian Affairs map of 97 reservations that were west of the Mississippi River and clearly visible in the original map. With the exception of the Osage Reservation, we exclude Oklahoma because reservations in that state are no longer federally recognized. The data on surplus land and the timing of allotment come from *Indian Land Tenure, Economic Status, and Population Trends* prepared by the Office Indian Affairs of the U.S. Department of Interior in 1935. Based on that report, 68 of the reservations in our sample were allotted to some extent, and surplus land was given to white settlers in 21 reservations. Of the 68 reservations that were allotted, some land was alienated and sold out of trust on 56 reservations. The spatial definitions of shale basins and plays come from the U.S. Energy Information Administration.

Appendix 3: Statistical Comparisons of Ownership and Shale Quality

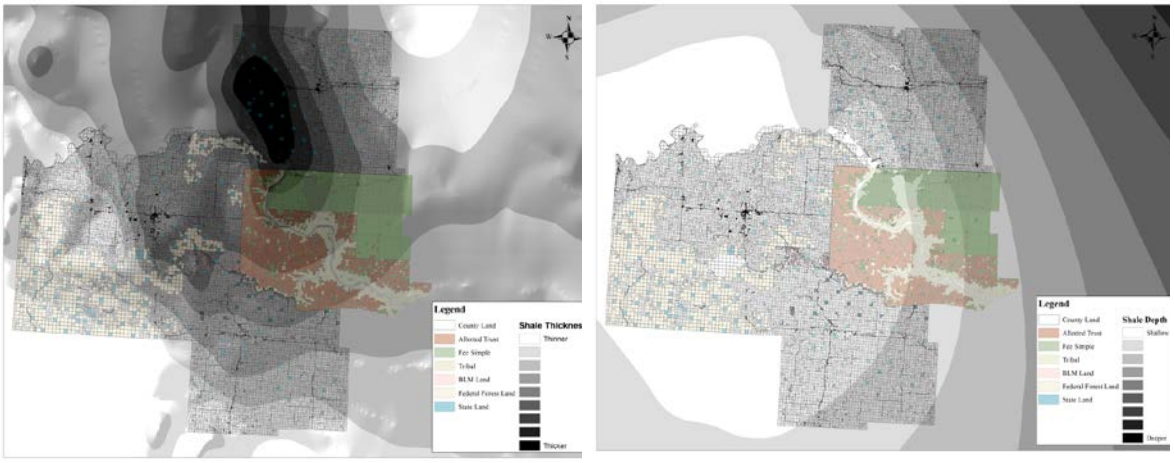
Although ownership patterns were not intentionally selected based on shale endowments, the process may have unintentionally biased some patterns towards higher quality shale. We investigate this possibility empirically by examining how shale thickness and depth correspond to tenure, parcel sizes, and shapes. In general, thicker shale holds more oil. Shale depth can be important too, because drilling costs tend to rise with greater depth. For these reasons, we follow the lead of Weber et al. (2016), by measuring the economic quality of shale with its thickness-to-depth ratio at the parcel level. We first multiply thickness by 100 to reduce the number of decimal places in the regression below. For parcels within an oil field, this variable ranges from 0.13 to 1.82 with a mean of 0.98. Off of oil fields, the variable has mean of 0.85.[1]

Panel A of figure A2 shows the depth of the Bakken formation. Darker areas indicate deeper shale formations. Lighter areas in panel B indicate thicker shale. The visual evidence in figure 4 indicates there is variation in the quality of shale within and across tenure types. Visually, it is difficult to detect any clear patterns of bias but we note the following. First, the western part of the reservation has deeper but thicker shale than the eastern part. Second, the northern part of the reservation covers relatively thick shale.

To evaluate the exogeneity of shale quality, we run parcel-level regressions with thickness-to-depth as the dependent variable. The full data set consists of 51,083 parcels but we constrain our attention to the 41,979 parcels on oil fields, which are depicted in figures A2 and A3. For the reservation, we obtained parcel-level GIS data on mineral tenure for allotted and tribal parcels from the Bureau of Indian Affairs (BIA) in addition to GIS data on which areas of the reservation have fee simple mineral rights. Because the BIA does not identify the parcel boundaries for fee parcels, we overlapped the reservation tenure files with GIS data on parcels for Dunn, McKenzie, and Mountrail counties to fill in the missing parcel boundaries.

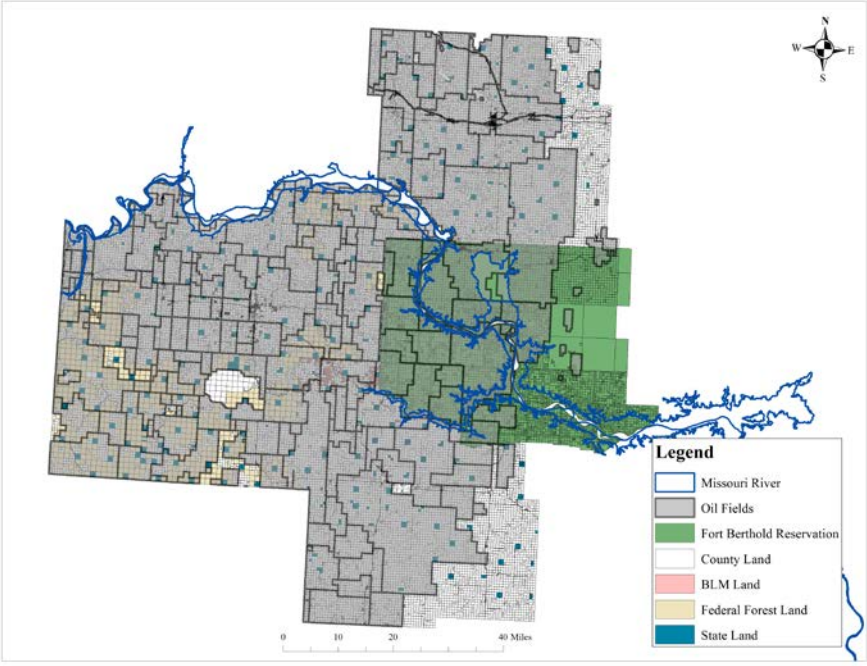
[1] The thickness and depth data come in the form of contour lines. To convert those data to numerical values, we employed the "Topo to Raster" interpolation tool in ArcGis. Shale thickness for parcels on an oil field ranges from 10.6 to 141.9 with a mean of 78.4 feet. Shale depth ranges from 5,494 to 8,644 feet with a mean of 8,070. We note that thickness-to-depth is strongly correlated with well productivity, conditional on drilling (results available upon request).

Figure A2: Shale Depth and Thickness



Notes: Panel A (on the left) depicts the depth of shale in the Bakken formation, with the darker shades indicating thicker shale. Panel B (on the right) illustrates the thickness of the shale, with lighter shades indicating thicker shale. The data are based on GIS data provided by the U.S. Energy Information Administrative office.

Figure A3: Study Area of Fort Berthold and Surrounding Counties with Oil Fields



Notes: This map depicts parcel boundaries and present-day oil fields on the Fort Berthold Indian Reservation and surrounding counties. The surrounding counties are Dunn, McKenzie, and Mountrail. Data on oil fields come from the North Dakota Oil and Gas Commission.

We estimate (A1) using OLS, where *i* indicates the parcel and *j* is one of the 203 oil fields spanning the 41,979 parcels. The variable Tenure encompasses allotted trust, fee simple, forest service, BLM, and state lands. The variable Acres represents the size of the parcel. The variable Longside is a measure of parcel shape. It is the length of the parcels' longest side, in miles. Holding constant parcel acres, an increase in Longside means the parcel is skinnier (e.g., progressively more linear than square).

(A1) $$Thick\text{-}to\text{-}Depth_{ij} = \alpha_j + \gamma Tenure_{ij} + Acres_{ij} + Longside_{ij} + \varepsilon_{ij}$$

Table A2 presents the estimates. The even numbered columns include oil field fixed effects and the odd numbered columns do not. The omitted category in the odd-numbered columns is private parcels off the reservation. The omitted category in the even numbered models is a private parcel, off reservation, in oil field 1.

The results in the odd numbered columns reveal systematic relationships between shale quality and ownership *across* oil fields. The results in columns 1 and 5, for example, suggest that average shale quality on the reservation exceeds average quality off the reservation, and that fee parcels tend to be endowed with the highest quality shale. Columns 3 and 5 show that larger, skinnier parcels sit above lower quality shale By contrast, results in the even numbered columns demonstrate no statistically significant relationships *within* oil fields, which are relatively homogenous spatial units by design. [2] Administrative regulations for drilling and spacing wells vary by oil field, and multiple oil companies operate in a single field. This is an important consideration for testing hypotheses about the causal effects of ownership on oil drilling patterns. Our primary results exploit within-field variation in tenure to 1) control for differences in spatial regulations across oil fields (e.g., well spacing requirements) and 2) maintain exogeneity of tenure with respect to the quality of the shale.

To summarize, the inadvertent subdivision of shale created variation in tenure, parcel sizes, and shapes that we expect to influence the probability of drilling. This variation is verifiably exogenous to a measure of shale quality, within oil fields.

[2] Oil fields are formed when a drilling company seeks approval to start a project; they are a spatial regulatory unit originally designed to internalize common pool externalities associated with extracting conventional oil. We find similar results when exchange the dependent variable for in equation 1 with individual measures of thickness and depth (rather than thickness-to-depth). In both cases, there are not significant differences across tenure types within the reservation, but there are some differences between off and on reservation parcels.

Table A1: Correlations between Thickness-to-Depth and Parcel Tenure

	(1)	(2)	(3)	(4)	(5)	(6)
Fee	0.348***	0.0259			0.325***	0.0236
	(0.0882)	(0.0185)			(0.0823)	(0.0195)
Allotted Trust	0.139**	0.0241			0.134**	0.0224
	(0.0535)	(0.0175)			(0.0517)	(0.0182)
Tribal	0.181***	0.0235			0.165***	0.0205
	(0.0555)	(0.0159)			(0.0546)	0.0107
State	0.00875	-0.00100			0.0430	0.00236
	(0.0348)	(0.00574)			(0.0358)	(0.00627)
U.S. Forest Service	-0.316***	-0.00164			-0.181***	0.0107
	(0.0744)	(0.00467)			(0.0687)	(0.00838)
U.S. BLM	0.0208	0.0104			-0.00636	0.00736
	(0.0452)	(0.0127)			(0.0452)	(0.0126)
Parcel Acres			-0.000516***	-0.0000311	-0.000277***	-0.0000378
			(0.000123)	(0.0000216)	(0.000102)	(0.0000269)
Longside			-0.0937**	-0.00596	-0.0748**	-0.00455
			(0.0426)	(0.00751)	(0.0350)	(0.00770
Constant	0.937***	0.920***	1.066***	0.899***	0.993***	0.914***
	(0.0471)	(0.0131)	(0.0460)	(0.00268)	(0.0507)	(0.0139)
Oil Field Fixed Effects	No	Yes	No	Yes	No	Yes
N	41979	41979	41979	41979	41979	41979
Adjusted R^2	0.121	0.955	0.052	0.955	0.138	0.955

Notes: Robust standard errors in parentheses, clustered by oil fields. * $p < .1$, ** $p < .05$, *** $p < .01$. The data used in these estimates are summarized in table 2.

Appendix 4: Robustness of Parcel Level Estimates of the Probability of a Lateral

Table A2
Alternative Specifications for Parcel Level Estimates of the Probability of a Lateral

	Baseline	Omits city parcels	Omits city parcels and neighborhoods with > 50% city	Includes govt. parcels
	(1)	(3)	(3)	(4)
Parcel acres	0.00163***	0.00162***	0.00163***	0.00114***
	(0.000156)	(0.000156)	(0.000156)	(0.000119)
Parcel longside	0.203***	0.191***	0.182***	0.234***
	(0.0294)	(0.0284)	(0.0257)	(0.0208)
Fee parcel indicator	0.00781	0.0145	0.0631	-0.0482
	(0.0521)	(0.0543)	(0.0563)	(0.0506)
Allotted trust parcel indicator	0.0286	0.0307	0.0572	-0.0113
	(0.0539)	(0.0556)	(0.0594)	(0.0504)
Tribal parcel indicator	-0.00777	-0.00907	0.00741	-0.0308
	(0.0560)	(0.0575)	(0.0611)	(0.0560)
St. dev. of neighbor size	-0.00609***	-0.00626***	-0.00723***	-0.00481***
	(0.00202)	(0.00198)	(0.00189)	(0.00129)
No. of tenure regimes	-0.0266***	-0.0322***	-0.0307***	-0.0114
	(0.00987)	(0.0108)	(0.0103)	(0.00766)
Off reservation neighbors	-0.00179***	-0.00175***	-0.00191***	-0.00196***
	(0.000373)	(0.000381)	(0.000383)	(0.000292)
Fee neighbors	-0.00164***	-0.00161***	-0.00299***	-0.00177***
	(0.000293)	(0.000293)	(0.000357)	(0.000238)
Allotted trust neighbors	-0.00334***	-0.00318***	-0.00312***	-0.00270**
	(0.000868)	(0.000871)	(0.00107)	(0.00106)
Tribal neighbors	0.00165	0.00266*	0.00147	0.00160
	(0.00112)	(0.00160)	(0.00152)	(0.00150)
Covariates	All	All	All	All
Oil field fixed effects	Yes	Yes	Yes	Yes
City parcels	Yes	No	No	Yes
Neighborhoods >50% city	Yes	Yes	No	Yes
Parcel coordinates	No	No	No	No
Neighborhoods govt. land	No	No	No	Yes
Adjusted R-squared	0.312	0.268	0.295	0.312
Observations	27,656	23,614	22,573	41,963

Notes: Standard errors are clustered by oil field. * p<0.1, ** p<0.05, *** p<0.01. A parcel's neighborhood includes all parcels touching a one-mile radius extending from the parcel's exterior boundary. All specifications control for the slight variation in the total area of the one mile radius, due to variation in the size of parcels on the exterior of the radius. Column 1 is the baseline specification from column 4 of table 5. Column 2 drops all parcels that are within a city. Column 3 drops all parcels that are within a city and also non-city parcels in neighborhoods with greater than 50 percent city parcels. Column 4 also includes the following controls: (a) indicators for Bureau of Land Management (BLM), U.S. Forest Service (FS), and North Dakota (ND) state owned parcels and (b) the number of BLM, FS, and ND parcels in each neighborhood.

Table A3
Robustness Checks of Lateral Probability with Spatial Error Corrections

	(1)	(2)	(3)	(4)
Parcel Variables				
Parcel acres	0.00145***	0.00137***	0.00150***	0.00161***
	(0.0000683)	(0.0000700)	(0.0000705)	(0.0000719)
Parcel longside	0.212***	0.205***	0.217***	0.197***
	(0.0168)	(0.0168)	(0.0169)	(0.0161)
Fee parcel indicator	-0.0708***	-0.0792***	0.0203	0.0667***
	(0.0133)	(0.0134)	(0.0142)	(0.0196)
Allotted parcel indicator	-0.00529	-0.0193	0.0601***	.07391***
	(0.0220)	(0.0220)	(0.0218)	(0.0245)
Tribal parcel indicator	-0.0202	-0.0413*	0.0146	0.0375
	(0.0220)	(0.0221)	(0.0217)	(0.0249)
Neighbor Variables				
St. dev. of neighbor size	-0.00457***	-0.00490***	-0.00611***	-0.00576***
	(0.000619)	(0.000650)	(0.000674)	(0.000818)
No. of tenure regimes	-0.0291***	-0.0282***	-0.0236***	-0.0259***
	(0.00589)	(0.00588)	(0.00581)	(0.00576)
Off reservation neighbors	-0.0000641***	-0.000685***	-0.00119***	-0.00184 ***
	(0.0000131)	(0.000114)	(0.000121)	(0.000151)
Fee neighbors	-0.000412***	-0.000912***	-0.00124***	-0.00166***
	(0.0000164)	(0.0000939)	(0.0000977)	(0.0001208)
Allotted trust neighbors	-0.00187***	-0.00210***	-0.00209***	-0.00318***
	(0.000441)	(0.000463)	(0.000456)	(0.000582)
Tribal neighbors	-0.000350	0.0000192	0.00117**	0.00256***
	(0.000471)	(0.000488)	(0.000495)	(0.000676)
Covariates	All	All	All	All
Oil field fixed effects	Yes	Yes	Yes	Yes
City parcels	Yes	Yes	Yes	Yes
Neighborhoods >50% city	Yes	Yes	Yes	Yes
Parcel coordinates	No	No	No	No
Neighborhoods govt. land	No	No	No	No
Adjusted R^2	0.541	0.542	0.552	0.585
Observations	27,656	27,656	27,656	27,656

Notes: Spatial HAC standard errors reported in parentheses. Following Hsiang (2010), these models are estimated using a GMM approach that allows for arbitrary forms of spatial correlation in the error term, as described in Conley (2008). * p<0.1, ** p<0.05, *** p<0.01. A parcel's neighborhood includes all parcels touching a one-mile radius extending from the parcel's exterior boundary. All specifications control for the slight variation in the total area of the one mile radius, due to variation in the size of parcels on the exterior of the radius.

Table A4
Parcel Level Estimates of Horizontal Line (Lateral) Extent

	Y = Linear Miles of Horizontal Lines		Y = Linear Miles Per 100 Acres	
	(1)	(2)	(3)	(4)
Parcel Variables				
Parcel acres	0.00569***	0.00591***	0.00418***	0.00450***
	(0.000273)	(0.000307)	(0.000873)	(0.00101)
Parcel longside	0.236***	0.209***	0.534***	0.570***
	(0.0391)	(0.0381)	(0.168)	(0.176)
Fee parcel indicator	0.0251	0.0683	0.167	0.0698
	(0.0970)	(0.0856)	(0.216)	(0.254)
Allotted trust parcel indicator	0.123	0.0802	0.406*	0.198
	(0.0989)	(0.110)	(0.229)	(0.259)
Tribal parcel indicator	0.0398	0.0213	0.347	0.150
	(0.118)	(0.119)	(0.300)	(0.288)
Neighbor Variables				
St. dev. of neighbor size	-0.0136***	-0.0105*	-0.0283***	-0.0320***
	(0.00497)	(0.00584)	(0.00940)	(0.0100)
No. of tenure regimes	-0.0550**	-0.0595**	-0.110**	-0.110**
	(0.0242)	(0.0247)	(0.0514)	(0.0544)
Off reservation neighbors	-0.00160*	-0.00264***	-0.00238	-0.00680*
	(0.000952)	(0.000871)	(0.00358)	(0.00378)
Fee neighbors	-0.00199***	-0.00264***	-0.00341	-0.00656**
	(0.000764)	(0.000695)	(0.00305)	(0.00312)
Allotted trust neighbors	-0.00496***	-0.00673***	-0.00717*	-0.0132**
	(0.00184)	(0.00217)	(0.00429)	(0.00564)
Tribal neighbors	0.00177	0.00271	-0.000982	-0.00535
	(0.00345)	(0.00365)	(0.0129)	(0.0138)
Covariates	All	All	All	All
Oil field fixed effects	No	Yes	No	Yes
City parcels	Yes	Yes	Yes	Yes
Neighborhoods >50% city	Yes	Yes	Yes	Yes
Parcel coordinates	Yes	No	Yes	No
Pseudo R-squared	0.247	0.313	0.053	0.074
Observations	27,480	27,480	27,480	27,480
Censored at ≤ 0	16,682	16,682	16,682	16,682

Notes: Standard errors are clustered by oil field and shown in parentheses. * p<0.1, ** p<0.05, ***p<0.01. A parcel's neighborhood includes all parcels touching a one-mile radius extending from the parcel's exterior boundary. All specifications control for the slight variation in the total area of the one mile radius, due to variation in the size of parcels on the exterior of the radius.

Appendix 5: Estimates of the Placement of Vertical Well Bores

In table A5 we estimate the effects of subdivision and tenure on whether or not parcel *i* has a well bore, and on the number of bores. Recall that a bore is the vertical portion of a horizontal well. It's placement on a particular parcel may be important because the surface owner of that parcel is positioned to benefit financially for allowing well-pad infrastructure to be housed on his land.

To appreciate why a parcel's tenure may be important for the placement of vertical bores, we refer back to figure 2. The vertical intercepts in Figure 2 depict the number of excluders for whom consent would be needed if the entire horizontal line was under a single, large parcel. For fee parcels, the parcel owner must grant permission and a permit is required by North Dakota.[3] For allotted parcels, multiple owners of the single parcel must grant permission and permits are required by multiple federal agencies such as the Bureau of Indian Affairs and the U.S. Bureau of Land Management (Regan and Anderson 2014, Kunce et al. 2002).[4] For tribal parcels, multiple tribal agencies are also typically involved – especially if there are archaeological and cultural considerations regarding surface disturbances. We have drawn figure 2 under the assumption that tribal ownership engenders more veto power (exclusion rights) that must be overcome before a drilling project is launched, regardless of it spatial extent. This assumption means, for example, not only that there is more red tape in government decision making but also that approval over controversial and potentially environmentally harmful projects such as fracking requires more administrative procedures and consensus gathering.

The upshot is that oil drillers may prefer to avoid drilling through tribal shale unless they can exploit the spatial, single-owner advantage of extending a line through more tribal shale. The table A5 estimated of λ_T provide tests for this effect. The estimates in columns 1-2 employ a linear probability model for $Y = 1$ if the parcel has a

[3] Although surface owners have no legal standing to stop a drilling project, they typically must be negotiated with because the oil developer needs to place infrastructure such as pipelines, compressor stations, and water impoundment facilities next to the main vertical well pad. One-time payments for allowing this infrastructure can be large; in some areas of horizontal gas fracking development, for example, landowner payments for compressor stations has ranged from hundreds of thousands to millions of dollars and payments for water impoundment construction has ranged from $40,000 to $70,000 (Boslett et al. 2015).

[4] Drilling under allotted trust land and tribal land does not formally require permission from the state of North Dakota but the oil and gas regulations of the state and the permitting process is generally followed.

well bore. The estimates in columns 3-4 use a poisson model to estimate the count of well bores, which ranges from 0 to 30 across parcels.

The two most noteworthy results in table 5 are the coefficient estimates on λ_T and λ_F in column 2. These coefficients indicate that tribal parcels are less likely to have well bores, and that fee parcels are more likely to have them when compared to the omitted, off-reservation private parcel category. The column 2 coefficients are large. Relative to the mean probability of 7.96 percent, the $\hat{\lambda}_T$ =-0.037 point estimate means the probability of having a well bore decreases by 46.5 percent on tribal parcels. The $\hat{\lambda}_F$ = 0.032 point estimate means the probability of having a well bore increases by 40.2 percent on fee parcels. This finding suggests that oil companies prefer to locate on-reservation well bores on fee and not tribal land, presumably because negotiating a surface access contract with the tribe entails a higher transaction cost when compared with the cost of negotiating with private surface owners.

Table A5
Parcel Level Estimates of Horizontal Well Bore Location

	OLS estimates of Y = 1 if parcel has a horizontal well bore		Poisson Estimates of Y = No. of horizontal well bores	
	(1)	(2)	(3)	(4)
Parcel Variables				
Parcel acres (100s)	0.04786***	0.04668***	0.3362***	0.3349***
	(0.005376)	(0.005514)	(0.05412)	(0.05695)
Parcel longside	-0.008175	-0.01033	0.03533	0.05411
	(0.009072)	(0.009452)	(0.1263)	(0.1308)
Fee parcel indicator	0.03231*	0.03202**	0.1873	0.1546
	(0.01871)	(0.01452)	(0.1795)	(0.1921)
Allotted trust parcel indicator	0.01836	0.02382	0.3390	0.1909
	(0.02049)	(0.01696)	(0.2831)	(0.2754)
Tribal parcel indicator	-0.04978***	-0.03791**	-1.5861***	-1.6604***
	(0.01560)	(0.01631)	(0.4406)	(0.4439)
Neighbor Variables				
St. dev. of neighbor size	-0.001856***	-0.001607*	-0.03108***	-0.02719***
	(0.0006303)	(0.0008656)	(0.008889)	(0.008916)
No. of tenure regimes	0.0005092	-0.0004315	0.03530	0.03388
	(0.004955)	(0.004892)	(0.09659)	(0.09267)
Off reservation neighbors	-0.0006307***	-0.0007883***	-0.01312***	-0.01665***
	(0.0001340)	(0.0002202)	(0.003168)	(0.003860)
Fee neighbors	-0.0006228***	-0.0007358***	-0.01265***	-0.01538***
	(0.0001072)	(0.0001717)	(0.002528)	(0.002963)
Allotted trust neighbors	-0.001604***	-0.001467***	-0.02214***	-0.02211***
	(0.0003020)	(0.0004127)	(0.004877)	(0.006652)
Tribal neighbors	-0.0005451	-0.0005099	-0.007279	-0.0001790
	(0.0003628)	(0.0004410)	(0.01159)	(0.01064)
Covariates				
Thickness-to-depth ratio	3.5450**	2.3342	113.49***	24.724
Feet to water (000s)	-0.002142***	-0.003572**	-0.03152***	-0.05262***
No. Neighbors underwater	-0.0007712**	-0.0009464**	-0.01393	-0.01964**
Topographic roughness	-0.00006101	-0.00002546	-0.0004564	0.0004475
City indicator	0.009665	0.0001227	-0.4851	-0.7611
Feet to railroad (000s)	0.0002839	0.0005732	0.007782	0.001662
Road density in radius	0.0007139***	0.0009311***	0.0001238***	0.0001730***
x coordinate of parcel (000s)	0.00006507		-0.004853***	
y coordinate of parcel (000s)	0.0002370**		-0.0002760	
Oil field fixed effects	No	Yes	No	Yes
R-squared	0.056	0.075		
Observations	27,480	27,480	27,480	27,480

Notes: Standard errors are clustered by oil field and shown in parentheses. * p<0.1, ** p<0.05, *** p<0.01. A parcel's neighborhood includes all parcels touching a one-mile radius extending from the parcel's exterior boundary. All specifications control for the slight variation in the total area of the one mile radius, due to variation in the size of parcels on the exterior of the radius.

Appendix 6: Parcel Level Estimates of the Effects of other Government Holdings on Lateral Probability

To assess whether the empirical patterns might generalize to other government holdings, beyond tribal ownership, here we compare private subdivision versus government ownership for the sample of off-reservation parcels. Off the reservation, government parcels are managed by the state of North Dakota, the U.S. BLM, and the USFS. These government parcels are sometimes situated within oil fields alongside privately owned parcels (figure Ae). Regression results in table A6 – which employ the same specifications as table 3 – show that the probability of line penetration decreases with the number of private neighbors within the 1-mile radius. By contrast, increases in the number of BLM neighbors do not have robust effects on drilling probabilities. Increases in the number of neighboring state-owned parcels actually increase drilling probabilities in our preferred specification (column 4). Both findings are consistent with one of our main arguments, that private subdivision around a parcel reduces the parcel owner's leverage in attracting oil development. We do not emphasize drilling patterns around and on USFS parcels because the USFS Dakota Prairie Grassland area in our sample has unique drilling restrictions. The observed pattern of drilling on and around BLM and state parcels, however, are similar to those on and around tribal parcels suggesting the tribal results generalize to other forms of collective ownership.

Table A6
Estimates of Horizontal Line Probability for Off-Reservation Parcels

	(1)	(2)	(3)	(4)
Parcel Variables				
Parcel acres	0.00113***	0.00107***	0.00110***	0.00119***
	(0.000128)	(0.000124)	(0.000129)	(0.000131)
Parcel longside	0.255***	0.240***	0.253***	0.228***
	(0.0251)	(0.0210)	(0.0206)	(0.0200)
US BLM parcel indicator	-0.111***	-0.120***	-0.119***	-0.115***
	(0.0382)	(0.0385)	(0.0382)	(0.0415)
ND state parcel indicator	-0.0152	-0.0236	-0.0225	-0.0402
	(0.0518)	(0.0499)	(0.0500)	(0.0477)
Neighbor Variables				
St. dev. of neighbor size	-0.00546***	-0.00564***	-0.00652***	-0.00346**
	(0.00216)	(0.00224)	(0.00193)	(0.00202)
No. of tenure regimes	-0.0119	-0.00694	-0.0106	-0.000123
	(0.0122)	(0.0118)	(0.0113)	(0.00989)
Off Res. (private) neighbors	-0.00614***	-0.00682***	-0.00605***	-0.00779***
	(0.000596)	(0.000623)	(0.000680)	(0.000524)
US BLM neighbors	-0.00320**	-0.00225*	-0.00153	-0.00101
	(0.00133)	(0.00135)	(0.00135)	(0.00159)
ND state neighbors	0.00567	0.00632	0.00987**	0.00864***
	(0.00432)	(0.00384)	(0.00389)	(0.00252)
Covariates				
Thickness-to-depth ratio	26.53***	25.47***	37.96***	29.83***
Feet to water (000s)	-0.0109***	-0.0111***	-0.00854***	-0.0121***
No. Neighbors underwater	-0.00755***	-0.00794***	-0.00777***	-0.00857***
Topographic roughness	-0.000146	-0.000103	-0.000115	-0.0000204
City indicator		-0.113*	-0.0925	-0.0862
Feet to railroad (000s)		-0.00209	-0.00140	-0.00318*
Road density in radius		0.0000123***	0.0000155***	0.0000190***
x coordinate (000s)			-0.00184***	
y coordinate (000s)			-0.000384	
Oil field fixed effects	No	No	No	Yes
Adjusted R-squared	0.225	0.231	0.238	0.309
Observations	32,057	32,057	32,057	32,057

Notes: Standard errors are clustered by oil field and shown in parentheses. * p<0.1, ** p<0.05, *** p<0.01. A parcel's neighborhood includes all parcels touching a one-mile radius extending from the parcel's exterior boundary. All specifications control for the slight variation in the total area of the one mile radius, due to variation in the size of parcels on the exterior of the radius. US BLM indicates parcels owned by U.S. Bureau of Land Management and ND state land denotes parcels owned by the state of North Dakota. The sample excludes all parcels on the Fort Berthold reservation.