Creating Anticommons:

Historical Land Privatization and Modern Natural Resource Use[1]

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Abstract: We explain how subdividing the commons to promote efficient use of one resource (agricultural land) inadvertently discourages efficient use of another (shale oil). We test for the presence of this 'anticommons' problem by exploiting a natural experiment on the Bakken, one of the world's largest oil fields. Before oil was discovered, U.S. land allotment policies created a mosaic of private, tribal, and fragmented ownership to shale on and around the Fort Berthold Indian Reservation. We compare horizontal drilling patterns across over 40,000 parcels on and off the reservation during the 2005 to 2015 fracking boom. We find that subdivision and fragmented ownership delayed and reduced the probability of drilling, whereas parcels surrounded by contiguous tribal lands were more quickly exploited. We estimate that allotment reduced expected compensation from the boom by an amount greater than reservation income from other sources. The evidence demonstrates how land privatization can inadvertently impair spatially coordinated resource use and suppress rents that would otherwise accrue from an unanticipated resource boom.

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

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I. Introduction

Some of the world's indigenous populations lack formal property rights to land and evidence suggests this is a hindrance to development. The main problem is that informal rights of exclusion are often too weak to encourage current users to invest in land improvements that would increase future income streams (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 rights of exclusion 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, Brinkhurst and Kessler 2013). Where they have been applied, the programs have, in general, stimulated parcel-specific investments as theory predicts.[2]

We study an unintended consequence of privatization that may offset some of the benefits. Subdividing land beneficially encloses the commons for some land uses (e.g., agriculture) but can create anticommons problems for other future uses. Anticommons problems arise when multiple individuals hold exclusion rights to a resource that is effectively used only with consent of each owner, and when failure to obtain consent prevents Pareto improving use (Heller 1998, Buchanan and Yoon 2000, Heller 2008). Our concern is that subdivision of land into small parcels may stunt future income from resource uses requiring management at larger spatial scales (e.g., wind farming, shale oil and gas extraction, wildlife conservation, and water trading). 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. Roughly 41 million acres of communal Indian land was subdivided into 320, 160, 80, and 40 acre parcels and allotted to individual Native American families with the goal of encouraging productive farming (Carlson 1981).[3] Some allotted parcels were individually privatized and others were not, with multiple family heirs retaining exclusion rights. Other tribal lands were never allotted and

[2] Galiani and Shcargrodsky (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 Lakshmi 2008, Galiani and Schargrodsky 2010). But some studies fail to find significant improvements in agricultural investment after titling (Brasselle et al. 2002, Jacoby and Minten 2007). Guerriero (2016) provides an explanation for why weak property rights may be preferred in some settings.

[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).

remain held in common by tribal members through their governments. As a result, modern Indian reservations are a complex patchwork of surface and subsurface tenure (Trosper 1978, Anderson 1995, Banner 2005). Empirical research suggests that privatized parcels have more housing investment (Akee 2009) and greater agricultural investments (Anderson and Lueck 1992), as standard models of property rights would predict.[4] This research does not study large-scale resources, such as wind and oil, which are more abundant than good farmland on many reservations but were not valuable when reservation boundaries were set and privatization occurred.[5]

We examine how land allotment has affected a valuable, modern form of resource development: shale oil extraction through hydraulic fracturing (fracking). The empirical analysis is based on a detailed case study of drilling on and around North Dakota's Fort Berthold Indian reservation during the fracking boom of 2005-2015. The analysis combines GIS data on land and mineral tenure with publicly available data on horizontal wells from the North Dakota Oil and Gas Commission. The parcels in our sample sit atop the highly productive Bakken oil field. The subsurface rights are divided into the mosaic of tribal land, allotted trust land, and fee simple parcels found on many reservations.

Our focus on shale oil development enables novel tests of anticommons for three reasons.[6] First, modern technology of oil extraction –horizontal fracking – requires coordinated exploitation of a landscape's subsurface. This is because shale extraction is executed by drilling a horizontal line, or "lateral," that extends about two miles from a vertical well pad; profitable oil units in our study area 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 to develop a proposed drilling project. Although this type of spatial coordination challenge can arise wherever parcels are small, the challenge is exacerbated on Indian reservations where there are also multiple owners of individual parcels due to heirship.[7] The challenge is

[4] A common challenge to identification in this literature is possible selection bias due to the fact that tenure is not exogenous to surface-based land characteristics (see Akee and Jorgensen 2014).

[5] Indian reservations were often sited on poor agricultural land and in areas lacking natural resources known to be valuable at the time of siting (see Carlson 1981, Dippel 2014, Anderson et al. 2017).

[6] 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.

[7] 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

plausibly less severe for projects that would extract oil from beneath contiguous swaths of tribally owned lands. This is because rights to exclude an economically feasible drilling project are consolidated under government ownership.

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.

A third reason for focusing on shale is that land allotment and the resulting tenure arrangements were exogenous to shale endowments. This exogeneity is rare in studies of property rights and natural resource use, because property rights in most settings are determined by resource quality (Besley 1995, Kaffine 2009, Galiani and Schargrodsky 2012). In our setting, ownership of shale was inadvertently subdivided in patterns determined by agricultural potential prior to the discovery of oil, as we describe in section 3. Because of this exogeneity, we are able to estimate causal effects of property rights, parcel sizes, and shapes.[8]

To motivate the empirical tests, we model the "anticommons" as a coordination failure, building from Buchanan and Yoon (2000), but we also model pure transaction costs. Transaction costs and coordination problems increase with N, the number of exclusion rights that must be granted to complete an economically feasible drilling project of fixed size. The probability of a project declines with N regardless of whether coordination failure or transaction costs are the driving mechanism. If coordination failure is the driving mechanism, then the probability declines because royalty rates requested by mineral owners increase with N, thereby decreasing the attractiveness of the project to an oil developer. In terms of welfare, this individually rational behaviour collectively lowers expected rent from the shale. Mineral owners may inadvertently benefit from the coordination failure, however, if the price of oil unexpectedly rises; this may induce drilling in spite of the high royalties (see Kellogg 2014).

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and land assembly problems studied extensively in the economics literature (see Brooks and Lutz 2016 and Isaac et. al 2016).

[8] 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.

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 oil boom. We find the probability a parcel was penetrated by a horizontal well – which generally means the owner was compensated for his shale - is strongly affected by private parcel size and shape. Larger and more rectangular parcels were more likely to be exploited than smaller squares. For example, a one standard deviation increase in parcel size is associated with a 39 percent increase in the probability of compensation. 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, Hornbeck and Keniston 2014, Brooks and Lutz 2016).

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 around it significantly decreases the probability the parcel has been penetrated by a horizontal well. The negative effect is twice as large for land that was subdivided into allotted trust tenure 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 and 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 conversion of all mineral ownership to tribal ownership. The estimates imply the conversion would have increased the probability that a reservation parcel's shale was exploited during the 2005-2015 boom by 33 percent. Whereas private ownership is found to induce parcel-specific investments in the literature cited above, this is evidence that communal ownership has advantages in the development of resource uses requiring spatial coordination.

We also test for the possibility that oil wells in allotted and privatized areas earned more revenue and delivered higher royalty payments. Conditional on drilling, we find that projects penetrating more private and allotted parcels happened later in time: about 21 days per fee simple parcel and 36 days per allotted parcel in a neighborhood. As a consequence of the later timing, the projects penetrating allotted parcels earned higher revenue. Moreover, our analysis of royalty rates in oil leases indicates that owners of allotted and fee simple parcels tended to request higher royalties when compared to leases with tribal governments.

Accounting for the lower compensation earned by tribal projects, we still estimate that transferring ownership to tribes would have resulted in at least a 16 percent increase in expected rents 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 $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 qualitatively consistent with Freyrer et al. (2016), who find large 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 the Fort Berthold reservation and elsewhere, residents were already exposed to local drilling disamenities (e.g., noise, pollution, crime, congestion) whether or not compensated for shale. The worst scenario, it seems, is to have institutional constraints on compensation while still being exposed to the disamenities of a resource boom environment.

II. Background Literature: Exclusion, Commons, and Anticommons

In the United States and other countries, ownership of natural resources follows the coordinate boundaries of surface ownership. This ownership 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

[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

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.

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 the puzzle of 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 prohibitively high contracting costs to fuller resource use. Heller (2008) gives more 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

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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 (Smith 2000, Barzel 1997, Allen and Lueck 2003).

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; hence underutilization of the resource relative to sole ownership.[11] The transaction cost channel also causes underutilization, because the net return of transitioning to a new resource use is lowered by the assembly costs of contracting with each owner, reducing the demand for the resource.

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 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 entirely. 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

[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, however. 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.

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. Though the tragedy of the parking commons was solved by privatizing parking stalls, doing so created an anticommons at the scale of the lot itself. 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, wildlife corridors, and land conservation networks.

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]

Sole private ownership of large contiguous landscapes is rare, at least in the United States, but government ownership is not. How does the literature on commons and

[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 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.

anticommons view government ownership? On one hand, contiguous government ownership has the advantage of a sole private owner if a single public decisionmaker "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 economic value of natural resources it manages and "may not perceive lost revenue … to be central to their decisionmaking" (Heller 1998, 655). Government may 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 anticommons-induced shale oil drilling delays might emerge from the two mechanisms reviewed in section II. We begin with a description of technology and then model leasing frictions.

A. Drilling Technology

Although hydraulic fracturing (fracking) and horizontal drilling were experimented with for several decades, their large-scale use did not emerge in the United States until about 2005 (Zuckerman 2013). A well is first drilled vertically from a main well pad to the depth of the shale, which runs approximately parallel to the surface and holds the trapped oil. The well is then turned horizontally and driven for typically several thousand feet through the shale. When hydraulic fracturing is added, as is the case in the Bakken, 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.[15] Oil is pumped out of the well until the area around the horizontal portion of the well is mostly drained.

The economic costs of horizontal 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.,

[15] The horizontal portion of the well that runs through the shale parallel to the surface is referred to as a lateral.

pipeline, waste water impoundment facilities, compression stations).[16] 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). One reason is that it becomes increasingly difficult to "steer" the lateral with increased distance. The second reason is that steering and capturing oil requires an increasing amount of pressure as horizontal distance increases.[17]

The technological costs of drilling a shale area are minimized by optimizing a horizontal line length that trades-off the fixed cost of drilling additional wells versus the rising marginal cost of line length. We denote this optimal length with h^*, and the associated minimized cost $c|_{h=h^*}$ with 'c'. In what follows we interpret this line length as defining the spatial scale of drilling, and consider it fixed.[18]

B. Project Surplus and Transaction Costs

If it is costless to contract with shale owners, the expected surplus from a well is

(1) $S = pq - c$,

where p is the expected price of oil, per unit, and q is the quantity of oil output per well. Abstracting from uncertainty and discounting, S represents the expected present value of drilling the well.[19] Changes in any parameter can change whether or not a project yields positive surplus in expectation, thereby influencing the probability of well 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.

[16] This cost is roughly in the range of about $10 million for a well in the Bakken formation.
[17] 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).
[18] 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.
[19] 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, and $E(p_t)$ indicates expected prices over the life of the well, and ρ^t is a discount factor. We abstract from uncertainty and dynamics because making these features explicit would add bulk to the theory without providing additional insights.

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.[20] In section IV we emphasize that transaction costs can be high on 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).[21] 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

(2) $S = pq - c - \tau N$.

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.[22]

C. Allocation of Surplus

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

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

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*. It follows that the threshold expected price needed to trigger drilling is rising in *R*. In what follows, we assume drilling occurs only if $\pi \geq 0$.

[20] 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.
[21] 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 ..."
[22] Shoemaker (2003, 760) cites an example in which 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.

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.[23] Applying their framework here, each shale owner chooses a royalty rate in an attempt to maximize his expected payout. 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:

(4) $(1 - R)pq - c \geq 0$

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 affect the drilling decision. This allows us to express the probability of drilling terms of the CDF for *c*:

(5) $$\begin{aligned} Pr(Well) &= \Pr[(1 - R)pq - c \geq 0] \\ &= \Pr[c \leq (1 - R)pq] \\ &= F[(1 - R)pq]. \end{aligned}$$

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

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

We focus on the interior portion of the CDF in (6), 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 $[\underline{c}, \bar{c})$.[24]

[23] 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.

[24] 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

Each shale owner maximizes his expected payout, given by

$$(7)\quad E(pay_i) = \Pr(well) \times (pay \mid well = 1) = \frac{(1-R)pq - \underline{c}}{\bar{c} - \underline{c}} \times \frac{pqr_i}{N}.$$

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

$$(8)\quad \max_{r_i} \left[\frac{(1-\sum r_i / N)pq - \underline{c}}{\bar{c} - \underline{c}} \right] \times \frac{pqr_i}{N}, \text{ with } \sum r_i = r_i + \sum r_{-i}.$$

The individual chooses a royalty rate, taking as given the royalty rates chosen by all other shale owners along the proposed h^* line, denoted by $-i$. The first-order condition is

$$(9)\quad \frac{\partial E(pay_i)}{\partial r_i} = \frac{pq}{N(\bar{c} - \underline{c})} \left[pq - \underline{c} - \frac{pq}{N}(2r_i + \sum r_{-i}) \right] = 0.$$

In a symmetric Nash-Equilibrium, as modelled by Buchanan and Yoon (2000), we have $\sum r_{-i} = (N-1)r_i$. The solution for the royalty rate is given by

$$(10)\quad r_i^N = R^N = \left(\frac{N}{N+1} \right) \left(\frac{pq - \underline{c}}{pq} \right), \ \forall i$$

where the superscripts 'N' highlight its importance in this solution concept for R. In terms of comparative statics, $\partial R^N / \partial N = 1/(N+1)^2 \frac{(pq - \underline{c})}{pq}$ is strictly increasing in N. This strict increase results from uncoordinated royalty requests that are individually optimal, conditional on the royalties requested by other shale owners. This is the discrete choice version of the Buchanan and Yoon (2000) result; adding excluders with veto power over a resource raises the aggregate price of resource use.[25]

Buchanan and Yoon (2000) do not model pure transaction costs but 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

$$(11)\quad r_i^{N\tau} = R^{N\tau} = \left(\frac{N}{N+1} \right) \left(\frac{pq - \tau N - \underline{c}}{pq} \right), \ \forall i$$

where the superscripts '$N\tau$' highlight the importance of transaction costs in this solution for R. There are two differences between $R^{N\tau}$ and R^N. First, $R^N > R^{N\tau}$ because, when transaction costs are sunk, the shale owners are able to extract additional rents because the driller would

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 $\bar{c}$.

[25] Buchanan and Yoon (2000) assume downward-sloping demand curve for the use of a resource with many exclusion rights, wheras we assume the investment is a yes/no decision that depends on the random variable c.

have to absorb additional $N\tau$ costs to drill in a different location. This comparison of royalty rates 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.

The second contrast is that $\partial R^{N} \big/ \partial N > 0$ while $\partial R^{N\tau} \big/ \partial N$ 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 and expected profit from drilling is unambiguous.

E. Probability of Drilling and Timing

Aside from royalties, our empirical analysis focuses on the probability and timing of drilling through shale areas of size h^* that vary in N, the number of owners. The theoretical framework provides clear predictions about the effect of N on these outcomes. Consider the probability of a well, now given by

$$(12) \quad \Pr(well) = \frac{(1 - R^{tN})pq - \tau N - \underline{c}}{\overline{c} - \underline{c}}.$$

Substituting $R^{N\tau}$ with the expression in equation (11) and differentiating yields the following comparative static, which is derived in the appendix

$$(13) \quad \frac{\partial \Pr(well)}{\partial N} = \frac{1}{\overline{c} - \underline{c}} \left[\frac{-1}{(N+1)^2} \left(pq - \tau N - \underline{c} \right) + \frac{\tau N}{N+1} - \tau \right].$$

The term in parentheses is defined only when $S > 0$. With this in mind, we can sign the comparative static. The term $1/(\overline{c} - \underline{c})$ is strictly positive. The term $-\left(pq - \tau N - \underline{c} \right)/(N+1)^2$ is negative or zero. The term $\tau N/(N+1) - \tau = -\tau/(N+1)$ is strictly negative. Hence, the probability of a well is negatively related to N—the key anticommons parameter—when we assume that transaction costs are not treated as sunk. What if transaction costs are considered sunk? To see that result, replace $\tau = 0$ in expression (13). This evaluation reveals that $\partial \Pr(well)/\partial N < 0$ regardless of whether or not one considers transaction costs sunk at the time of lease negotiations.

To evaluate how *N* affects the timing of drilling, conditional on drilling taking place, consider how *N* affects the threshold expected price needed to trigger drilling, given the equilibrium royalty rate. If drilling will occur only if expected profits are positive, then the threshold price is given by

$$(14)\quad \hat{p} = \frac{c}{(1-R^N)q} \quad \text{or} \quad \frac{c+\tau N}{(1-R^{Nt})q} \quad .$$

If transaction costs are sunk, then R^N is increasing in *N* implying $\partial\hat{p}/\partial N > 0$. Because $\hat{p}$ is rising in *N*, we infer that shale areas with smaller *N* will be drilled before those with larger *N*.

To summarize, the anticommons model yields the following key predictions.

1. The probability of leasing and drilling through a shale areas of size h^* decreases with *N*, the number of owners of shale in that the area.
2. Conditional on drilling, shale areas with fewer *N* will be drilled before areas with greater *N* (because the threshold price for profitable drilling increases in *N*).
3. The effect of *N* on royalty rates is ambiguous, as it depends on whether or not transaction costs are considered sunk at the time of lease negotiations.

F. Expected Rents and Discussion

What are the implications of a higher *N* for expected rents to shale ownership? Higher *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 a mathematical appendix that the net effect is negative: higher *N* reduces 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 it reduces 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. If future changes in prices and costs are anticipated, then large *N* cannot benefit resource owners *in expectation*.

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.[26] It sits beneath the Fort Berthold Indian Reservation and surrounding North Dakota land. The historical subdivision of these lands creates an ideal natural experiment for two reasons. 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 in North Dakota. 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. Background on 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 figure 1). Allotment was promoted to encourage agricultural investment[27] and, consistent with this claim, research indicates the scale and timing of allotment across reservations was determined primarily by agricultural land quality (Carlson 1981).

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 acreages for 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

[26] The Bakken, which began to boom around 2005, is one of the world's largest oil fields. Because of it, by 2012, North Dakota had surpassed California and Alaska to become the second largest oil producing state after Texas. By the end of 2012, the Bakken accounted for 10 percent of the entire nation's oil production (Zuckerman 2013).

[27] 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).

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. Hence, 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).

Figure 1 shows that many reservations that were allotted overlap shale deposits, but agricultural quality, rather than shale, was the main determinant of cross-reservation allotment (Carlson 1981).[28] 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 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 allotted after the mid-1910s have their communal mineral interests fully intact today. Most reservations, including the Fort Berthold, are mosaics of subdivided subsurface tenure.

B. Shale Ownership under Fort Berthold and Surrounding Counties

Figure 2 shows our study area, which is the Fort Berthold reservation and the surrounding shale-endowed counties of Dunn, McKenzie, and Mountrail. Today, there are numerous active oil shale fields in this area 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. Figure 2 also shows that some land in our study area

[28] The Allotment Act mimicked the 1862 Homestead Act, which promoted settlement of the U.S. West (Allen 1991). The Homestead Act granted to settlers 160 acre parcels except that certain parcels near railroad lines were 80 acre grants. To promote the settlement of less productive agricultural land, homestead acts of 1909 and 1916 raised the size of homesteads from 160 to 320, and then to 640 acres.

is owned by North Dakota, the U.S. forest service, and the U.S. Bureau of Land Management (BLM).[29]

Fort Berthold 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 3).[30] The majority of Fort Berthold was allotted but not released from trust. Some allotted parcels were later privatized (figure 3).

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 Garrison Dam episode explains why so much of the tribally owned shale today is by the river (figure 3); some 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.

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 conventional oil and gas 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 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.

C. 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

[29] The state trust lands were granted from the federal government in 1889 and are typically sections 16 and 36 of every township. The forest service and BLM land comprise failed homesteads, many that were purchased back during the 1930s. The forest service land mostly comprises the Dakota Prairie Grasslands: it is managed for wildlife and recreation and drilling for oil there is constrained.

[30] 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).

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. (2014), 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.[31]

Panel A of figure 4 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 2 and 3. 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. We explain the data set and sources in more detail in section V.

We estimate (1) 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).

[31] 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).

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

Table 1 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. [32] 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.

V. Data for Empirical Tests

To assess the effects of subdivision and tenure on modern oil drilling (horizontal fracking) 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 of key outcomes variables in both data sets.

A. Overview

[32] 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.

Our key outcome variables measure the location and timing of horizontal wells drilled into the Bakken formation during the boom and bust over 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. Figure 5 shows the location of well bores which are the vertical portion of a horizontal well. It also shows the location of laterals. We downloaded these data in May 2015, and they represent the accumulation of wells completed as of May 1, 2015, which roughly corresponds with the beginning of an at least temporary drilling 'bust.' During this 10-year period, 7,864 horizontal wells were drilled in our study area spanning 12,017 line miles.

Figure 6 indicates that our study area, which is most of the Bakken, accounted for the majority of wells drilled in North Dakota during 2005-2015. The Bakken produced 1.56 billion barrels of oil during this time period.[33] To understand the potential magnitude of royalty payments, multiply the average price per barrel over 2005-2015 (panel A), which was $85.5 in 2015 dollars, by the average royalty rate, which was 17.4 percent. This amount - $14.9 billion – is large and does not account for the flow of royalty payments earned on oil extracted over the well's full lifetime of perhaps around 25 years (MacPherson 2012).

Our empirical approach involves combining the spatial information summarized in figure 5 with temporal information in figure 6 to construct outcome variables. The outcome variables measure whether or not a parcel has been drilled, the timing conditional on drilling, and estimates of well revenue from the first 18 months of production. Timing is important because shale owners likely have positive discount rates, and because the price of oil varied over time.

Our empirical strategy also involves creating measures of subdivision, ownership fragmentation, and mineral tenure from the spatial data summarized in figure 5. The variables we create provide ways to proxy the key theoretical variable, N, which is the number of exclusion rights over the spatial expanse of profitable drilling project. Figure 7 illustrates how N changes with subdivision across 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 7 is zero. The slope of the fee simple line in Figure 7 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

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

exclusion rights—99 percent of allotted trust parcels on the Ft. Berthold Reservation have more than one owner. 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 but on-reservation parcels may not be forced into pools. This is a rationale for why *N* may grow at a slower rate off of the reservation.

The vertical intercepts in Figure 7 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.[34] 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).[35] For tribal parcels, multiple tribal agencies are also typically involved – especially if there are archaeological and cultural considerations regarding surface disturbances.[36] In the following sections we describe the specific proxies for variation in *N*, which are somewhat different in the parcel-level, well-level, and lease-level data sets.

B. Parcel-Level Data

Table 2 shows summary statistics of the parcel-level outcome variables that we have constructed and figure 8 illustrates our mapping from the spatial data to the variables. 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.[37] We measure the extent of drilling through a parcel by the miles of laterals beneath that parcel. Some parcels are drilled multiple times from multiple

[34] 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 (see Boslett et al. 2016).

[35] 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.

[36] We have drawn figure 7 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.

[37] 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 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.

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.[38] 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 (see figure 8). 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.[39] 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.

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 8 illustrates.

[38] 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.

[39] 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 rather than square, 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).

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 the shale's thickness-to-depth ratio discussed above. We have 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 2, 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

Table 3 summarizes the well-level data. The data set comprises the 6,554 horizontal wells for which we were able to match the bore with the laterals emanating from the bore.[40] The number of tenure regimes penetrated by laterals from a single well range from 1 to 3, but 91 percent of the lines from a well are contained within a single tenure regime.[41] The maximum number of parcels cut by lines from a well is 85, and the mean is 7.3 parcels. Figure 8 illustrates an example of how our well-level variables map to the spatial attributes of a well.

We have also estimated the total 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 oil decline curve on the Bakken.

The oil decline calculations we use are based on the monthly productivity of a typical well in the Bakken, as estimated by Hughes (2013, p. 57). According to his estimates, a typical well produces 213,488 barrels during the first 48 months. Production from the well declines rapidly at first, and then the decline rate slows. For example, 19 percent of the 213,488 barrels are extracted during the first 3 months, 47 percent are extracted during the first year, and 70 percent during the first two years. We fit a hyperbolic decline-curve

[40] We match well bores to laterals by matching first on API number and then using proximity.
[41] There are 1261 wells on the reservation in this sample, with 61 percent penetrating multiple regimes.

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 of well productivity on the Bakken.[42]

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 total revenue earned by each well in its first 18 months of production.

Figure 7 graphs a summary of the results and table 3 shows summary statistics. Panel A plots average well productivity by the month in which production began. Wells productivity has been stable since early 2008 with a slight upward trend due to improvements in drilling technologies. Panel A indicates that the baseline well from Hughes (2013, p. 57) is a good approximation for average productivity observed in our sample, at least since 2008. Panel B plots average well 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, as shown in figure 6. Panel B also shows the impact of discount rates. 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.

D. Lease and Royalty 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 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

[42] Note that this "typical" 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.

produce a single observation for leases with matching terms in a given PLSS section.[43] 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 4 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 (and parcels) 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, in this section, by estimating the probability that a parcel has been penetrated by horizontal well. This is our best proxy for whether or not a parcel owner has been compensated (see footnote 39). We also estimate the timing of drilling and revenue from projects, conditional on drilling, along with royalty rates, conditional on leasing. From these pieces of evidence, we can estimate the impacts of subdivision and tenure on expected compensation, or rent, from the 2005-2015 oil boom.

A. Drilling Probability

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

[43] 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

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

The dependent variable is the indicator for whether or not the parcel's shale 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 section IV).[44]

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.[45]

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 $\beta_T = 0$ and $\beta_{-T} < 0$ for each of the non-tribal tenure types. In words, we predict that more finely subdividing a radius around a parcel into any form of private ownership will reduce the probability of drilling. This is why we predict $\beta_{-T} < 0$. 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 7. The key issue here is that subdivision into different tenure types had 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

[44] We include oil field fixed effects because our section IV 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.

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

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).

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.

Table 5 shows coefficient estimates for drilling probability. In all specifications we drop from the sample any parcel for which the 1-mile radius includes parcels owned by the USFS, the BLM, or the state of North Dakota. We drop these 13,792 parcels in our baseline specifications because rules on public lands - particularly the forest service tracts - limited fracking during our time period of analysis. Later we show the results are robust to keeping all government parcels in the sample. All of the standard errors in Table 4 are clustered by oil field but the results are robust to models that allow for other spatial error structures as discussed below.

The results in Table 5 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 includes oil field fixed effects and forces comparisons across tenure types while holding constant 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 overall mean drilling probability of 0.41. The longside coefficient of 0.203 means a one standard deviation increase implies a 0.07 increase in drilling probabilities, which is a 17 percent increase relative to the mean. We quantify the meaning of these and other changes in drilling probabilities in terms of foregone royalty income below, in section VII.

The column 4 point estimates indicate $\hat{\beta}_T = 0.0016 > \hat{\beta}_F = -0.0016 > \hat{\beta}_A = -0.0033$. 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, as predicted. 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.[46]

To appreciate magnitudes, consider what the coefficients imply about converting neighboring parcels to a different tenure type, while holding constant parcel sizes and shapes. We focus here on parcels and neighborhoods outside of city limits. 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. 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 0.0033 + 18.5 x 18.5 = 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.

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. Building from the above scenario, converting ownership from allotted and fee to tribal would 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 = 0.016 percentage points, or an additional 3.8 percent relative to the mean.

The signs on the other coefficients in Table 5 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 dissuade oil drilling in urban areas and in areas near bodies of water.

To summarize the results in table 5, 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. 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

[46] 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 A1).

number of tribal parcels in the radius. Table A1 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 A2 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 A3 tests for the effects of subdivision and tenure on the extent to which a parcel has been drilled, measured by the length of lines penetrating a parcel. This outcome variable is important because a parcel's shale can often be drilled multiple times, enabling parcel-owner compensation from multiple drilling projects. There we find the same pattern of results as in table 5: an increase in the number of neighbors in the 1-mile radius is associated with decreases in line miles, unless the neighbor's tenure type is tribal.

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 predicts that high *N* drilling projects will occur later in time than low *N* drilling projects. The theory also predicts that leasing will occur later in time in areas in which the transaction costs of leasing are high.

To assess the relationship between the timing of drilling and subdivision and tenure, we employ the well-level data summarized in table 3. 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 drilling.

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

$$\begin{aligned} Days_{wj} &= \alpha_j + \lambda_F Fee_{wj} + \lambda_A ATrust_{wj} + \lambda_T Trib_{wj} + \beta_O OffParc_{wj} + \beta_F FeeParc_{wj} \\ &+ \beta_A ATrustParc_{wj} + \beta_T TribParc_{wj} + \rho Regimes_{wj} + \gamma X_{wj} + \psi Linemiles_{wj} + \varepsilon_{wj} \end{aligned} \tag{16}$$

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 6 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 wells emanating from tribal land as in figure 7.

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

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

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 specification. The notation X_{sj} indicates the covariates, averaged at the section level. The tenure and number of parcel variables are defined in Table 4.

Table 7 shows the coefficient 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 7, 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 7 also provide an interesting contrast to those in table 6. 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 limited delays in drilling after leasing.

C. Project Revenues and Royalty Rates

As a final set of empirical tests, 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 16, using the well-level data set. Here the dependent variable is the log of revenue from each well during its first 18 months of production. Table 8 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 rents from drilling increased with N, conditional on drilling.[47]

To appreciate the magnitudes, consider what the coefficients imply about changing the tenure type through which the wells penetrated. If the wells penetrated tribal parcels instead of allotted, the well revenue for each parcel penetrated would decrease by 3.08 percent, based on the column 3 coefficient. Outside of cities, the average well on the reservation penetrated 3.24 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 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.

Finally, we test the effects of tenure on 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, a relationship of $R_A >$

[47] 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.

$R_F > R_T$ 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 we employ the lease data from DrillingInfo.com described above. Again we emphasize the important caveat that DrillingInfo.com does not provide data for individual leases, so the following results provide only a crude metric for variation in royalty rates. With these qualifiers in mind, we estimate the same regression model as in equation 17, but here the dependent variable is the logged royalty rate.[48]

Table 9 shows the results. 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 rates. Because the dependent variable is logged, the magnitudes are easy to interpret. Based on column 2, royalty rates requested in tribal leases were about 9.6 percent lower than off reservation leases. What explains this low price? Perhaps tribal governments with short planning horizons prioritized promoting oil development at the expense of getting the best price.

The column 3-4 regression results that do not control for year fixed effects are also of interest. This is because the timing of leases is endogenous to transaction costs (see table 7), and 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 and especially tribal land, requested royalty rates are higher because of the delay. For perspective on the magnitudes, consider the effects of replacing allotted tenure with tribal tenure. This would increase requested royalty rates by about 6.96% for each PLSS lease area converted to tribal. 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 rates are on projects not drilled.

[48] 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.

VII. Discussion: Punchlines and Qualifications

A. Back-of-the-Envelope Calculations

To summarize all of the results, we find the probability that a parcel owner was compensated for his shale during the boom declines sharply with the number of would-be excluders to an oil drilling project in an area surrounding his parcel. This finding means that subdivision and allotment may have reduced expected compensation from the boom, as our theory and anticommons logic predicts. However, we also find evidence that, conditional on drilling, projects involving more owners earned higher revenues during the first 18-months of production and likely also earned higher royalty rates.

What is the net effect of allotment on expected rents from the boom? To address this question, we imagine how expected compensation would have changed if the tribe held full mineral ownership at the boom's onset. To conduct this exercise, we extrapolate from the regression estimates to make out-of-sample predictions.

Table 10 shows the results. Tribal ownership would have increased the probability of compensation 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.

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 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.

These back-of-the-envelope simulations are rough, and there are reasons why they 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 April 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 (or benefits) 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. 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.

We also do not control for cultural differences and preferences across owners. If the average American Indian owner of allotted trust is more resistant to drilling than the average non-Indian 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.

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, we think the anticommons logic should apply to other comparisons of government versus subdivided private land. Evidence that it does is found in table A4 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.

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.[49] 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, namely 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 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 incomes 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. More generally, we add to a growing literature that seeks to better understand how historical, top-down institutions imposed on indigenous societies have affected modern economic outcomes.[50]

These findings may be 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

[49] 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.

[50] This literature includes Brown et al. (2017), Feir (2015), Akee and Jorgensen (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.

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.

Beyond the issue of indigenous lands, 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 controversial forced pooling rules that limit the power of individual landowners to holdup development. The findings here suggest that significant contracting delays 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 argue 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 often own subsurfaces.

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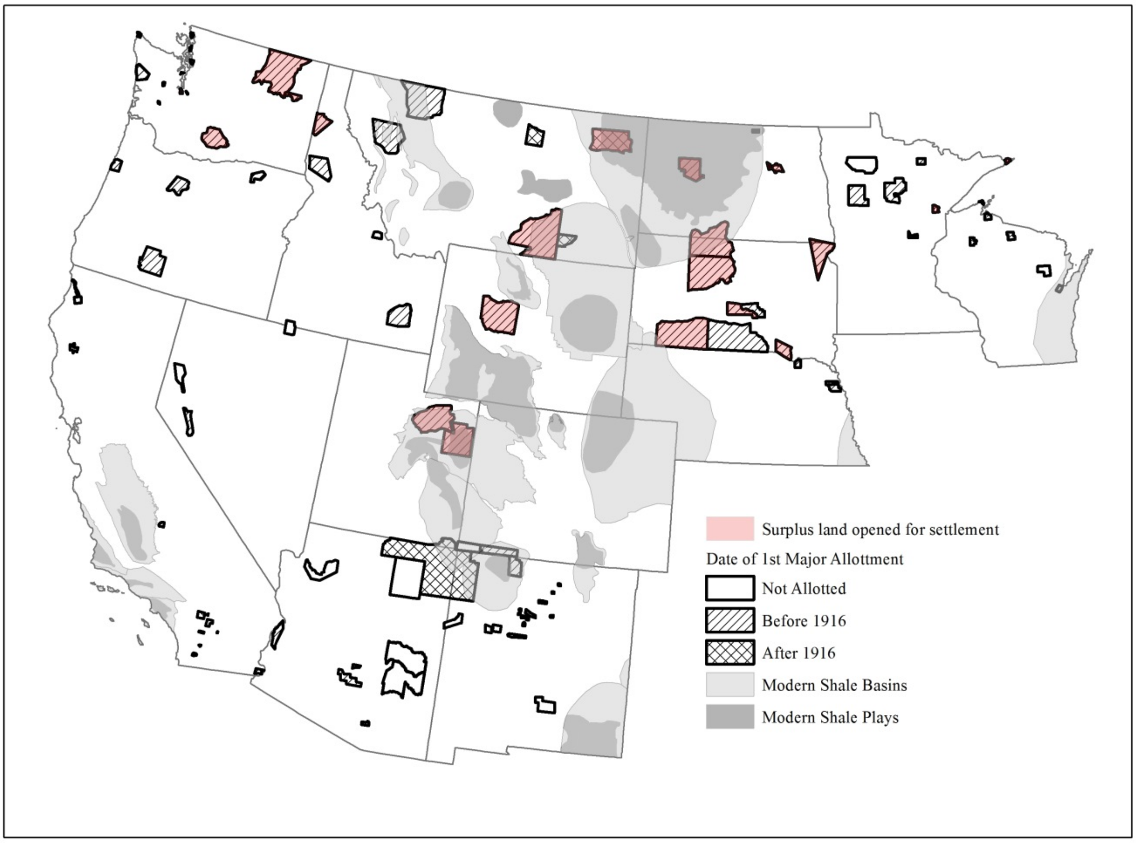
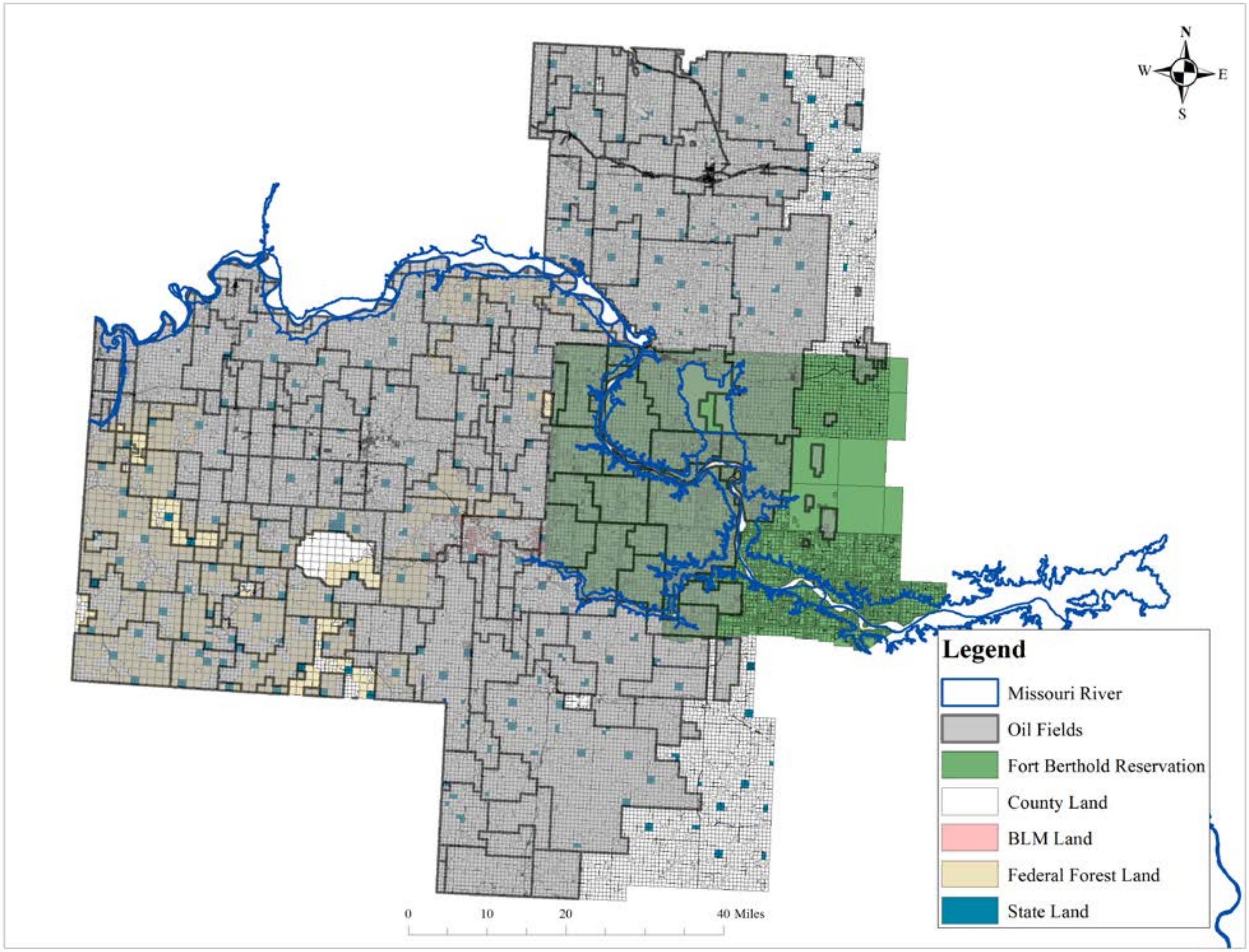
Figure 1: Timing and Distribution of Allotted Reservations



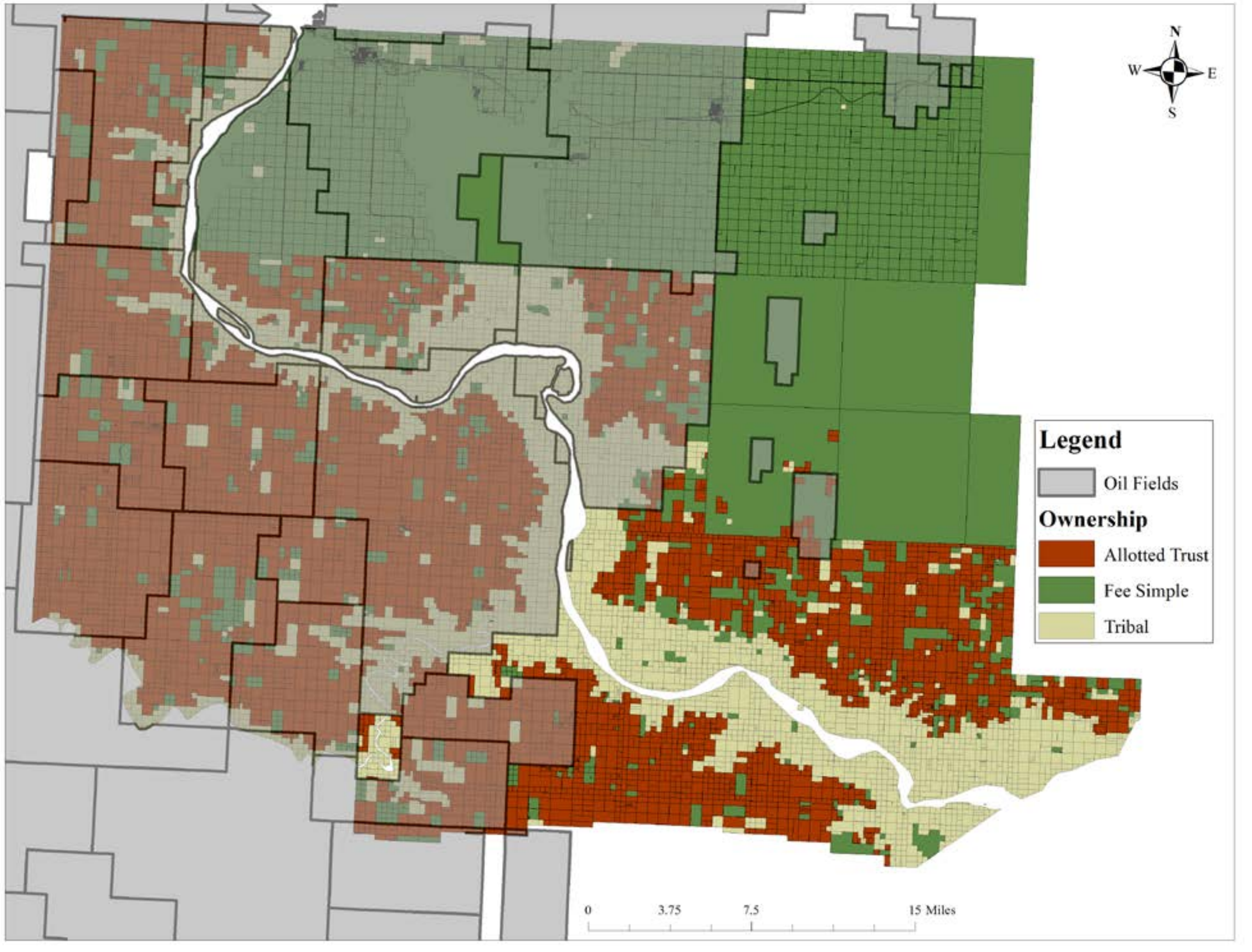
Notes: This map is based on our digitization of an 1890 Office of Indian Affairs map of 97 reservations that were west of the Mississippi River and clearly visible in the original map. With the exception of the Osage Reservation, we exclude Oklahoma because reservations in that state are no longer federally 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.

Figure 2: Study Area of Fort Berthold and Surrounding Counties with Oil Fields



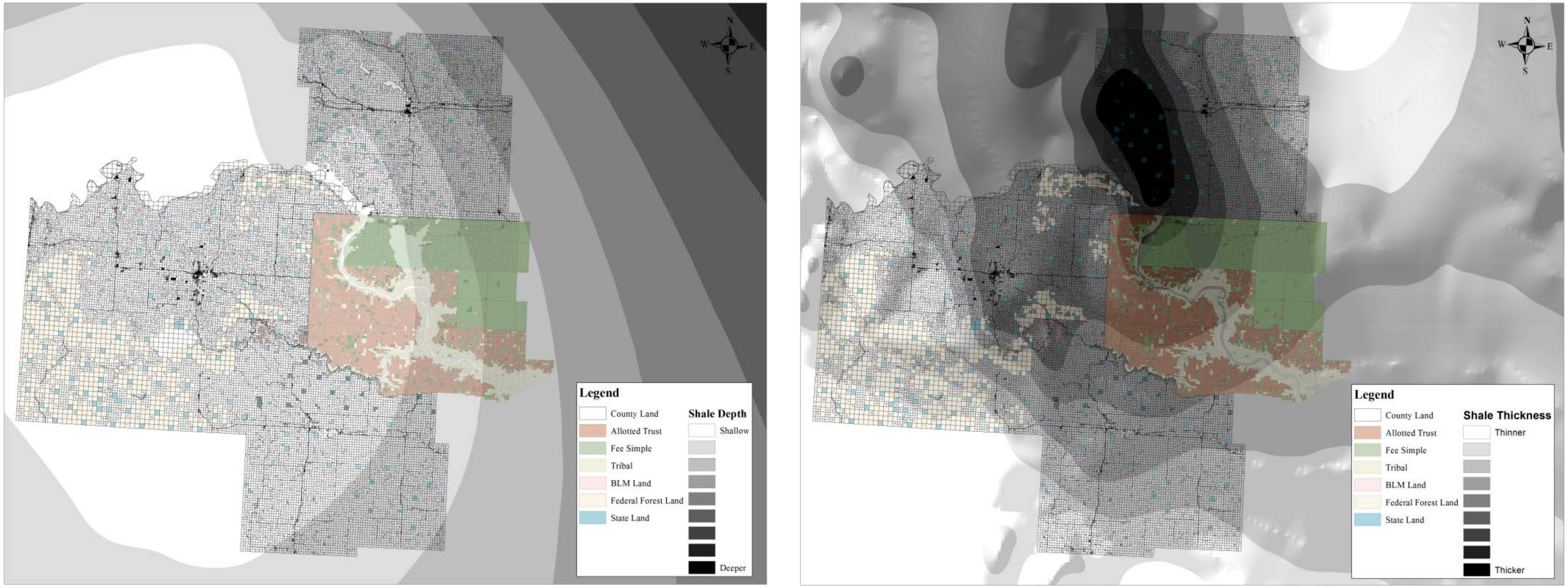
Notes: This map depicts parcel boundaries and present-day oil fields on the Fort Berthold Indian Reservation and surrounding counties. The surrounding counties are Dunn, McKenzie, and Mountrail. Data on oil fields come from the North Dakota Oil and Gas Commission.

Figure 3: Parcels and Mineral Tenure on Fort Berthold Reservation



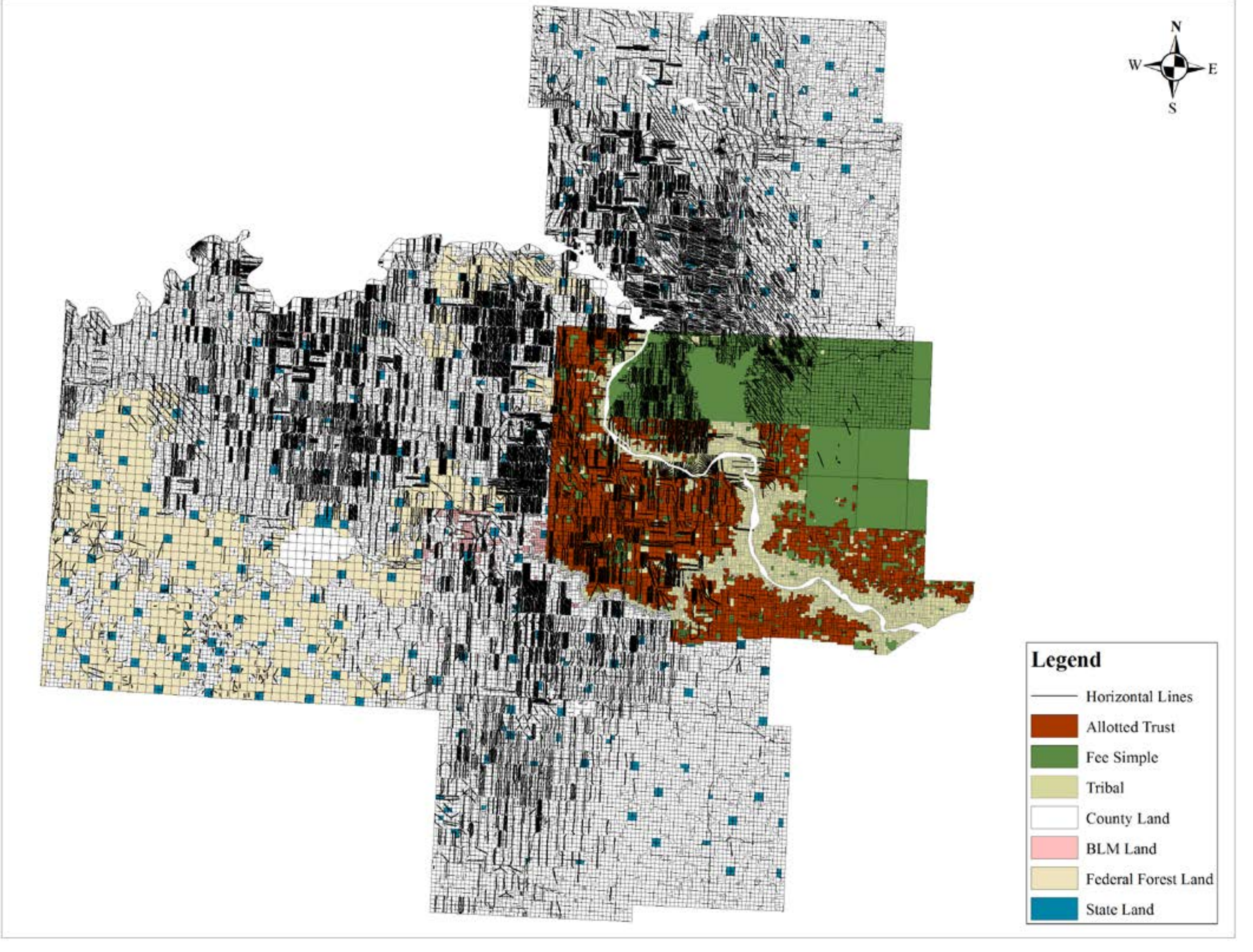
Notes: This map depicts parcel boundaries, oil fields, and mineral tenure types on the Fort Berthold Indian Reservations. The surrounding counties are Dunn, McKenzie, and Mountrail. The data sources are described in table 2. The areas lacking parcel boundaries are areas for which parcel level data are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

Figure 4: Shale Depth and Thickness



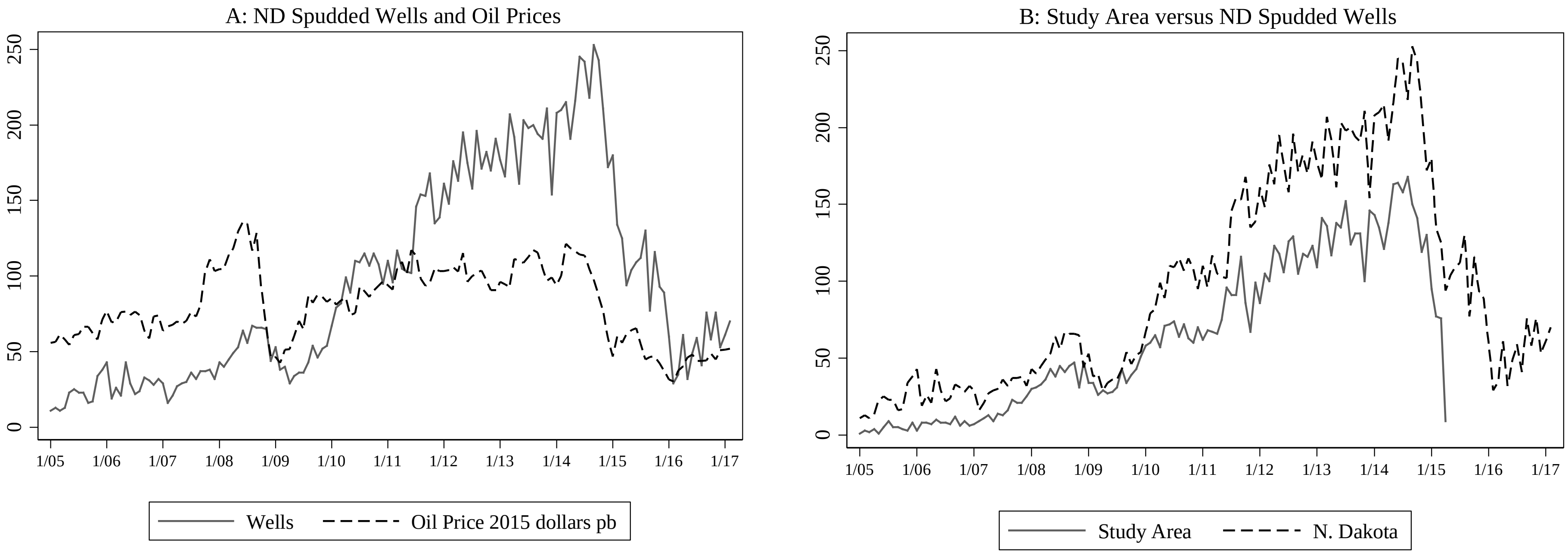
Notes: Panel A (on the left) depicts the depth of shale in the Bakken formation, with the darker shades indicating thicker shale. Panel B (on the right) illustrates the thickness of the shale, with lighter shades indicating thicker shale. The data are based on GIS data provided by the U.S. Energy Information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

Figure 5: Location of Horizontal Well Bores and Lines in Study Area



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

Figure 6: Drilling and 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.

Figure 7
Number of Exclusion Rights (N) over Horizontal Line of Length *h**

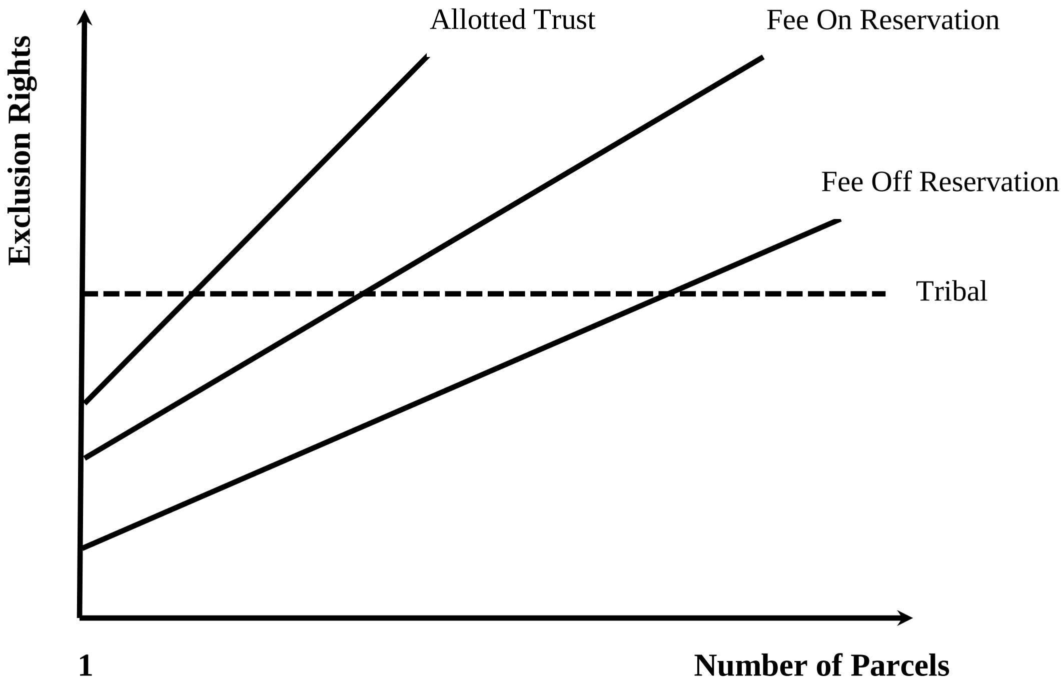
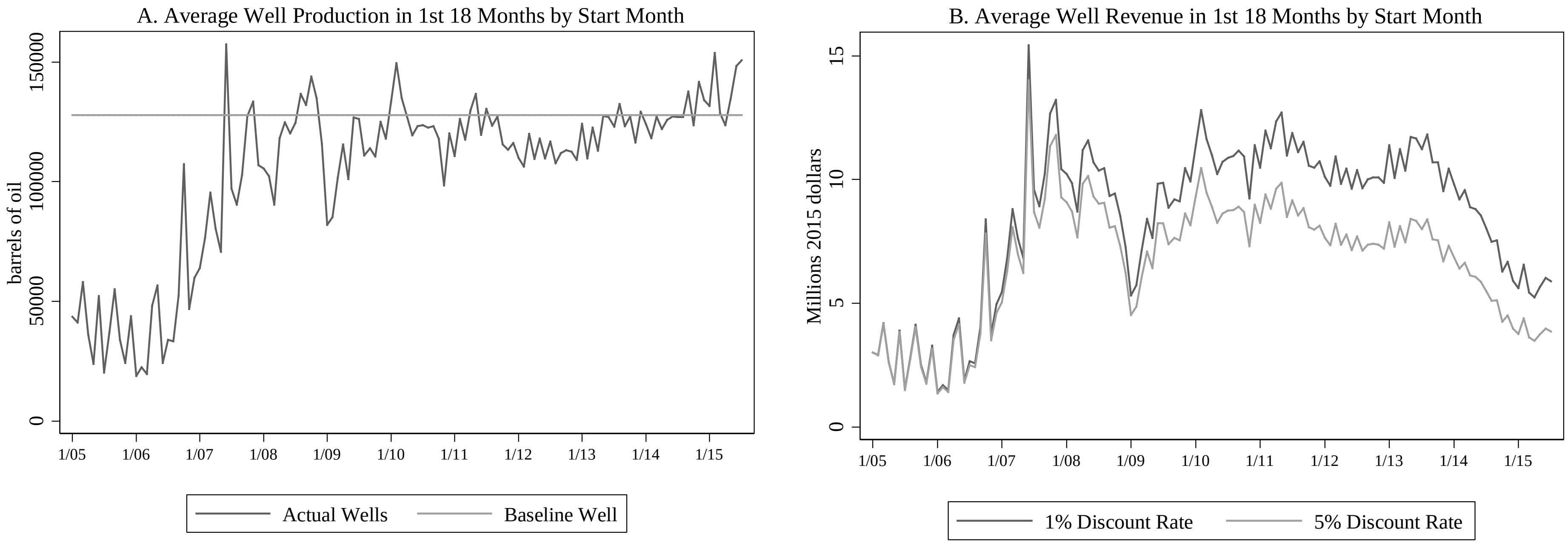


Figure 8: Estimated Production and Revenue from Sample Oil Wells
During first 18 Months of production



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.

Figure 9: 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 line under parcel *i*, the miles of line 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 lines through parcel *i* but not a well bore. In the figure on the right, there are lines 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 lines) 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 well lines penetrate. The images above do not show all of the wells and lines in the area, in order to keep the images more simple and informative. Figure A1 in the appendix shows the same images, along with other lines and wells in the mapped area.

Table 1:
Parcel-Level Correlations between Thickness to Depth and Tenure, Size, and Shape

	Across Fields	Within Fields	Across Fields	Within Fields	Across Fields	Within Fields
	(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.

Table 2: Summary Statistics from Parcel Level Data Set

	Mean	Std. Dev.	Min	Max	Description
Outcome Variables					
Horizontal Line Indicator[a]	0.4163	0.4929	0	1	=1 if the parcel was cut by at least one horizontal line as of May 1, 2015, otherwise = 0
Miles of Horizontal Lines[a]	0.2784	0.5584	0	10.47	The total length (miles) of horizontal lines 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 Neighbors	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, fractionated, 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 a National Elevation Dataset, and f) Authors calculations from North Dakota GIS Portal8 data.

Table 3: Summary Statistics from Well Level Data Set

	Mean	*Std. Dev.*	*Min*	*Max*	*Description*
Drilling Date and Distance					
Day when Drilled[a]	2314.0	739.73	13	3772	Days elapsed between January 1, 2005 and date in which the line was drilled
Lines from Well Bore[a]	2.2223	0.6248	1	12	Number of horizontal lines stemming from well bore
Miles of Horizontal Lines[a]	1.8896	0.5091	0.0002	8.1336	The total length (miles) of horizontal lines from the well bore
Well Revenue [b]					
Revenue 1% DR	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	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	7.0982	4.0748	0.0057	56.100	Estimated revenue during first 18th months, discounted from 2005 (in millions of 2015 $s)
Location of Well Bore					
Fee Parcel Indicator[a, c]	0.0876	0.2828	0	1	=1 if the well bore is on fee simple parcel, otherwise =0
Allotted Trust Parcel Indicator[a, c]	0.0992	0.2989	0	1	=1 if the well bore is on allotted trust parcel, otherwise =0
Tribal Parcel Indicator[a, c]	0.0079	0.0886	0	1	=1 if the well bore is on tribal parcel, otherwise =0
Off Res. Parcel Indicator[a, d]	0.7700	0.4208	0	1	=1 if the well bore is on an off reservation, private parcel, otherwise =0
No. of Parcels Well Lines Cut					
Tenure Regimes[a, c]	1.1030	0.3527	1	3	Number of different tenure regimes that all lines from a well penetrate
All Parcels[a, c, d]	7.2237	3.7259	1	85	Number of parcels that all lines from a well penetrate
Off Reservation Parcels[a, d]	5.8406	4.4257	0	85	Number of off reservation private parcels that all lines from a well penetrate
Fee Parcels[a, c]	0.5418	1.7667	0	28	Number of fee simple parcels that all lines from a well penetrate
Allotted Parcels[a, c]	0.6453	1.9430	0	15	Number of allotted trust parcels that all lines from a well penetrate
Tribal Parcels[a, c]	0.1960	1.1169	0	16	Number of tribal parcels that all lines from a well penetrate

Notes: This table 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.

Table 4: Summary Statistics from Lease Level Data Set

	Mean	*Std. Dev.*	*Min*	*Max*	*Description*
Outcome Variables					
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
Tenure & Parcel Variables					
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:
This table 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.

Table 5
Parcel Level Estimates of the Probability of a Horizontal Line

	Y = Horizontal Line 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 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 6
Well-Level Estimates of Days Elapsed before Drilling

	Y = Days until Drilling		
	(1)	(2)	(3)
<u>Location of Well Bore</u>			
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)
<u>No. of Parcels Cut by Lines</u>			
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)
<u>Covariates</u>			
Thickness-to-depth ratio	-15948.7	36872.6**	-817.2
Feet to water (000s)	-0.00369	0.00395	-0.00570
No. Neighbors underwater	3.031	2.528	2.389
Topographic roughness	0.133	0.210	0.0298
City indicator	-1.107*	-0.285	-0.0652
Feet to railroad (000s)	0.00529	0.00677*	0.0152**
Road density in radius	0.0114	0.0000180	-0.00097
x coordinate (000s)		-0.00810***	
y coordinate (000s)		-0.000908	
Field Effects			X
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 7
Lease Level Estimates of Time Elapsed before Leasing

	(1)	(2)	(3)	(4)
	Lease Year		Days since 1/1/2005	
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)
Thickness-to-depth ratio	-65.41***	43.26	-23359.2***	11189.9
Feet to river (000s)	0.000006**	0.000002	0.00258**	0.00161
Topographic roughness	0.00347**	0.00167	1.273**	0.653
Feet to railroad (000s)	0.000001	0.000036***	0.000792	0.0139***
Road density	0.123***	0.116***	43.59***	40.18***
City indicator	1.305***	1.741***	462.0***	625.1***
Constant	2006.8***	2008.7***	842.2***	1408.0***
	(0.185)	(0.377)	(67.36)	(137.4)
Oil Field Fixed Effects	No	Yes	No	Yes
N	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. * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

Table 8
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)
Covariates						
Thickness-to-depth ratio	31.50***	-26.55	31.83	31.20***	-30.23*	31.61
Feet to water (000s)	-0.000009***	-0.0000153***	0.0000002	-0.00008**	-0.00001***	0.000001
No. Neighbors underwater	-0.00405**	-0.00503***	-0.000685	-0.00410**	-0.00509***	-0.000757
Topographic roughness	-0.000297	-0.000373	-0.0000372	-0.000306	-0.000388	-0.0000626
City indicator	-0.000505	-0.00125**	-0.000629	-0.000385	-0.00118**	-0.000578
Feet to railroad (000s)	0.00000351	0.00000370	-0.0000020	0.000003	0.00000325	- 0.00000259
Road density in radius	0.00000556	0.0000155**	0.00000463	0.000004	0.00001**	0.000004
x coordinate (000s)		0.00000607***			0.000006***	
y coordinate (000s)		0.00000349***			0.000003***	
Field Effects			x			x
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.

Table 9
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)
Thickness-to-depth ratio	0.754**	-2.151	-1.054***	-1.450
Feet to river (000s)	-0.000000903***	-0.00000117***	-0.000000696***	-0.000000996***
Topographic roughness	0.0000557	-0.00000923	0.000148	0.0000513
Feet to railroad (000s)	-0.000000585**	-0.000000658*	-0.000000646***	0.000000202
Road density	0.00175	0.00215**	0.00473***	0.00522***
City indicator	-0.00703	0.00000293	0.0215	0.0417***
Constant	-1.803***	-1.803***	-1.747***	-1.691***
	(0.00679)	(0.0140)	(0.00722)	(0.0160)
2007	0.0212***	0.0223***		
2008	0.0663***	0.0686***		
2009	0.0919***	0.0995***		
2010	0.0949***	0.101***		
2011	0.158***	0.161***		
2012	0.168***	0.182***		
2013	0.186***	0.191***		
2014	0.167***	0.176***		
2015	0.191***	0.195***		
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. * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

Table 10
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 5, and are explained on page 29 of the text. The calculations in the second row are based on coefficient estimates in column 3 of table 8, and are explained on page 32 of the text. The royalty rate calculations are based on coefficient estimates in column 4 of table 9, and are explained on page 33 of the text. 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 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.

Mathematical Appendix

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

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

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

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

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

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

2. **Derivation of $\mathbf{Pr}(\boldsymbol{Well})$ and $\frac{\partial \mathrm{Pr}(Well)}{\partial N}$**

$$\Pr(Well_i) = \frac{(1 - R^{\tau N})pq - \tau N - \underline{c}}{\overline{c} - \underline{c}}$$
$$= \frac{1}{\overline{c} - \underline{c}}\left[pq - R^{\tau N}pq - \tau N - \underline{c}\right]$$
$$= \frac{1}{\overline{c} - \underline{c}}\left[S - R^{\tau N}pq\right]$$
$$= \frac{1}{\overline{c} - \underline{c}}\left[S - pq \times \frac{N}{N+1} \times \frac{S}{pq}\right]$$
$$= \frac{1}{\overline{c} - \underline{c}}\left[S - \frac{N}{N+1} \times S\right]$$
$$= \frac{S}{\overline{c} - \underline{c}}\left[1 - \frac{N}{N+1}\right]$$
$$= \frac{S}{\overline{c} - \underline{c}}\left[\frac{N+1-N}{N+1}\right]$$
$$= \frac{S}{(\overline{c} - \underline{c})(N+1)}$$
$$= \frac{\left(pq - \tau N - \underline{c}\right)}{(\overline{c} - \underline{c})(N+1)}$$

And hence

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

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

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

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

Putting together all of the pieces:

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

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

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

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

Table A1
Robustness Checks of Horizontal Line Probability

	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 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. 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 A2
Robustness Checks of Horizontal Line Probability with Spatial Error Corrections

[Coming Soon]

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 A3
Parcel Level Estimates of Horizontal Line 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.

Estimates of the Effects of other Government Holdings on Horizontal Line Probability

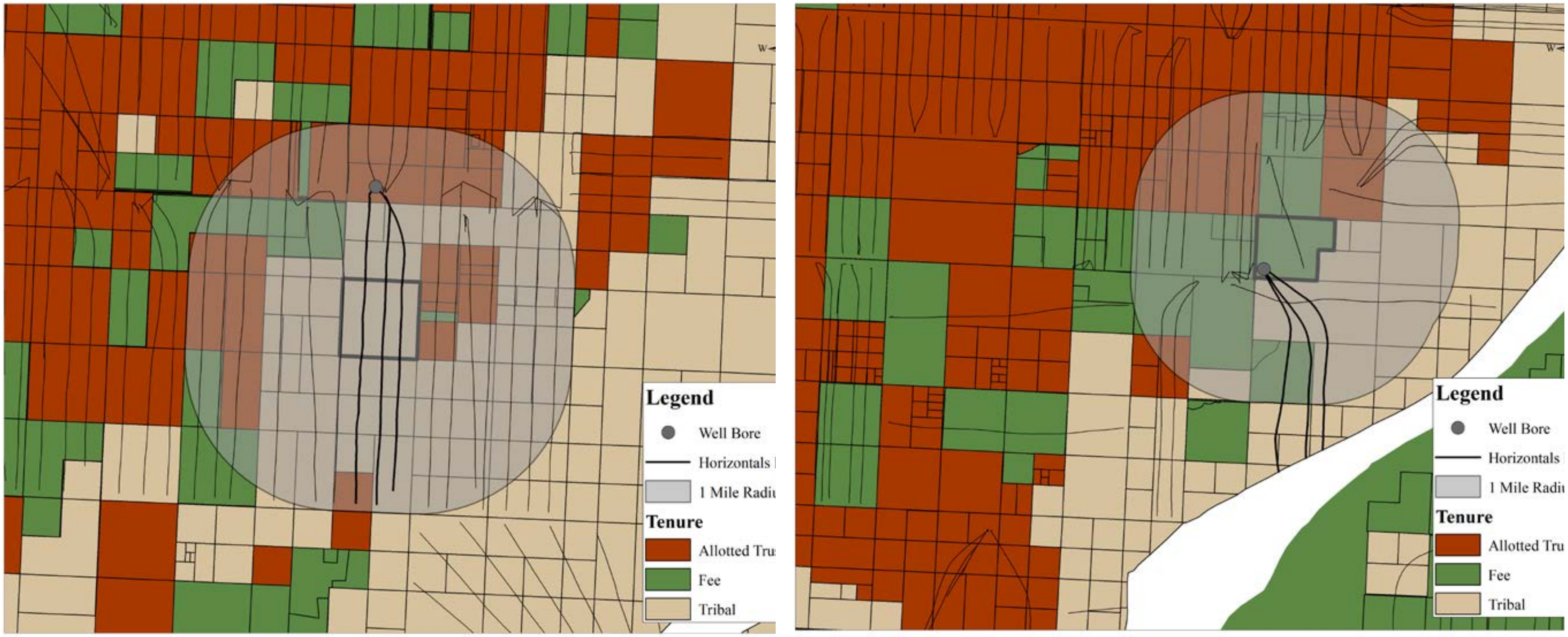
To assess whether the empirical patterns might generalize to other government holdings, beyond tribal ownership, here we compare private subdivision versus government ownership for the sample of off-reservation parcels. Off the reservation, government parcels are managed by the state of North Dakota, the U.S. BLM, and the USFS. These government parcels are sometimes situated within oil fields alongside privately owned parcels (figure 2). Regression results in table A4 – which employ the same specifications as table 5 – 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 A4
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.

Figure A1: Examples of our Mapping from Spatial Data to Empirical Variables, with All Lines Shown



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 line under parcel *i*, the miles of line 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 lines through parcel *i* but not a well bore. In the figure on the right, there are lines 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 lines) 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 well lines penetrate.