Federal Environmental Protection and the Distorted Search for Oil and Gas

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Abstract

The US federal government imposes costly environmental protection requirements for oil and gas operations on federally owned lands. This paper shows how these federal policies affected firms's drilling location choices and the resulting production. I exploit a natural experiment where federal and non-federal land were exogenously assigned. Using data from Wyoming, I find that revealed drilling and production outcomes are consistent with a model of search where costs are higher on federal land. I also find that low costs on non-federal land decreased drilling on nearby federal land while providing positive information spillovers. I show that drilling and production results are not driven by alternative mechanisms like common pools or irregular leasing policies. Back-of-the-envelope estimates suggest that federal regulations cost about $17 million (2010 dollars) per well.

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1 Introduction

Environmental policy makers try to balance promoting economic activity with protecting the environment. However regulators may be limited in the extent to which they can implement environmental protections. Firms may respond strategically to this incomplete protection, leading to unintended consequences. This paper explores how oil and gas firms have responded to partial environmental protection policies, where some plots of land have more environmental protection than other plots.

I examine the role of environmental protection on U.S. Federal Government lands. The United States Federal Government owns more than one quarter of the land in the U.S. and imposes special environmental policies on this land. I show how such policies can affect the oil and gas production both on federal land and on nearby non-federal land. Using a novel natural experiment where federal and non-federal land were exogenously assigned, I show how spatial patterns of federal ownership induce firms to shift where they drill as they search for and produce oil and natural gas. I find that federal policies lead to local leakage, where firms move drilling and production from federal land to less regulated areas.

Federal land management and environmental regulations have become increasingly controversial: Representative Doug Lamborn of Colorado argued: "In recent years we have seen a boom in energy jobs and economic growth on state and private lands ...I believe the only reason we haven't seen that same dynamic growth on federal lands is because of excess regulations" (Snow, 2013). The Western Energy Alliance has estimated that federal environmental protection measures are impeding the development of 58,480 jobs in Wyoming (SWCA Environmental Consultants, 2012). However, there is very little academic research examining the effect of these policies.

A major challenge in analyzing the impact of federal ownership is properly accounting for spillovers: The US has a complex patchwork of federally owned land, state government-owned land, and privately owned land. Each owner imposes dif-

ferent policies for oil and gas firms that affect the firm's willingness to drill on the owner's plot. Policies on one plot can have spillover effects on nearby plots. This is especially likely with oil and gas exploration, where drilling an exploratory well on one owner's plot is a substitute for drilling on another owner's plot. Shifted exploration patterns in turn affect later drilling and production outcomes. This paper models the exploration, drilling, and production process, showing how policies on one plot of land can have spillovers on nearby plots.

Even after accounting for spillovers, another challenge is the potential endogeneity of federal ownership. I exploit a novel natural experiment resulting from the Land Ordinance of 1785 where land was exogenously assigned to either federal government or state government ownership, as shown in Figure 1. Most land was in federal ownership, with the state government owning small, isolated, and regularly-spaced plots. I refer to these state land plots as "16/36 sections" because every 16th and 36th square mile plot of land was to be transferred to state ownership. This resulted in variation in federal versus state ownership, as well as variation in how close a given plot of federal land is to state land. I leverage both of these sources of variation to identify evidence of direct effects and spillover effects of policy through the mechanism of how firms search for oil and gas.

I write a simple model of search and learning that provides predictions for three types of land—state land, federal land close to state land, and federal land far from state land. I show that under higher federal costs, federal land close to state land will have less exploratory drilling relative to federal land far from state land because the firm shifts exploration to state land from nearby federal land. Lower costs on state land lead to higher drilling and production as well as a greater willingness to drill low productivity wells. I also show that proximity to state land has an ambiguous effect on drilling and production on federal land. Federal land that is closer to state land may have lower drilling and production because of long run effects of substitution to

state land. However federal land that is close to state land may have higher drilling and production if there are positive information spillovers from state land.

To test whether federal costs are higher and to explore how proximity to state land affects federal land, I compile extensive data on drilling and production in Wyoming. I focus on a region in southwest Wyoming where the federal-state ownership pattern has remained fairly strong. The drilling data allow me to examine the rollout of oil and gas drilling over time and space. Production data allow me to compare individual well productivity on different plots of land. The long range of data allow me to compare outcomes before and after the 1970's, when the federal government instituted most of the environmental protections for federal land.

Using an intent-to-treat specification, I find that ownership patterns have a significant effect on drilling and production. State land has is 35% more likely to have exploratory drilling relative to federal land far from state land, and up to 54% more likely to have exploratory drilling relative to federal land that is close to state land. This suggests that state costs are lower and that firms have shifted exploratory activity to state land from nearby federal land. I find evidence that there is long run leakage from federal land to state land as federal land close to state land has lower drilling and production. Because state land has lower costs, state land allows firms to drill under lower expected productivity: The average state well is 34% less productive relative to an average well on federal land far from state land. Federal land next to state land benefits from higher drilling rates on state land because drilling on state land helps firms discover lower productivity but still profitable fields that extend to nearby federal land. I also find that drilling patterns shifted after the 1970's, when new environmental policies were implemented for federal land.

I rule out alternate mechanisms that may explain these drilling and production patterns. I find no evidence that lower drilling on federal land is driven by the federal government withholding leases. Similarly, I also rule out the concern that differential

well production outcomes are driven by common pools.

I discuss the policy implications of these findings. I develop a simple structural estimation that gives a back-of-the-envelope estimate of the costs of operating on federal and state land. Point estimates suggest that federal regulations add a cost of about $17 million (2010 dollars) per well. I also discuss the spatial extent of spillovers and the role of information spillovers in leakage.

This paper is the first to show how spatially heterogeneous ownership patterns have affected the search for oil and gas. This paper builds on insights from two different strands of the literature: One shows how firms search for oil and gas, updating beliefs about the payoff from future wells from discoveries on past wells (Levitt, 2011; Hendricks and Kovenock, 1989; Lin, 2013). The other shows that local ownership and policies affect outcomes in the oil and gas industry, though this literature does not account for spillovers (Balthrop and Schnier, 2012; Fitzgerald, 2010; Fitzgerald and Stocking, 2014). I use insights about search and spillovers from the first strand and apply it to the heterogeneous ownership policy setting of the second. This paper also contributes to a small but growing literature about search and learning where agents use payoffs from one action to update beliefs about the payoffs from other actions (Crawford and Shum, 2005; Sullivan, 2010; James, 2012). I show how the econometrician can make inference about policies using revealed drilling and production outcomes without estimating a structural model.

In the next section, I discuss background information on the oil and gas industry, discuss my empirical strategy, and introduce the natural experiment. In section 3 I introduce the model of search. Section 4 introduces the data and the empirical specification, and section 5 contains the main empirical analysis. Section 6 tests whether alternative mechanisms are driving revealed drilling and production results. Section 7 discusses the policy implications of these findings, and section 8 concludes.

2 Background

In this preliminary section I discuss institutional details of federal environmental policy related to the oil and gas industry. I discuss why it is important to account for spatial ownership patterns, search, and spillovers in analyzing the effects of federal policy. I outline my empirical strategy, describing how I use a model coupled with a natural experiment where federal ownership was exogenously assigned. I discuss the historical origins of the natural experiment.

2.1 Federal Mineral Lands and Environmental Policy

The United States Federal Government owns and manages a significant fraction of land in the United States. Approximately 31% of land is in federal mineral ownership, meaning the federal government has the rights to extract oil, natural gas and subsurface minerals on those lands. The Bureau of Land Management (BLM) actively leases most of these lands to oil and gas firms.[1] Oil and gas firms obtain oil and gas leases, which allow them to drill for and extract oil and gas. Oil and gas firms must comply with federal requirements, including federal environmental protection measures.

US Federal lands have become subject to increasing environmental protection starting in the 1970's. For example, the National Environmental Policy Act (NEPA) of 1970 required the BLM to factor in environmental concerns in managing oil and gas operations. Similarly, the Endangered Species Act (ESA) of 1973 required that federal land policies must protect both endangered and vulnerable species, imposing stronger requirements on federal land than on other land. Other regulations that impose special protection for federal land include the Federal Land Policy and Management Act (1976), the Clean Air Act Amendment of 1977, and the National Historic

[1]The federal government also owns 28% of surface ownership in the United States. The BLM manages oil and gas leasing for BLM land, Forest Service land, and areas where the federal government owns mineral rights but private individuals own surface rights. Figures are calculated from table 3 of U.S. Department of the Interior, Bureau of Land Management (2012). These numbers do not include ownership of offshore mineral rights.

Preservation Act (1966), as well as executive orders and internal BLM policies (Pendery, 2010). The BLM soon established policies to manage oil and gas operations that satisfy NEPA, ESA, and a host of other regulations on federal land while still actively leasing oil and gas rights to firms (Skillen, 2013). Usually these policies specify actions that a firm must take before it is allowed to drill a well.

Anecdotally, firms report that these environmental requirements are costly. One industry representative in Wyoming told me that federal government lands are the most costly to operate on, followed by private land, with state-owned land the easiest to operate on. Conversations with industry representatives suggest that these environmental requirements are the biggest reason for higher federal costs. In contrast, industry representatives rarely mentioned other factors, such as the differences in annual rental fees and royalty rates.

2.2 Accounting for Ownership Patterns and Spillovers

While federal policy affects drilling on federal land, it may also affect drilling on nearby land. Spillovers of federal policy onto nearby land are likely because land ownership is fairly fractured, with adjacent private and state-owned land. This can be seen in Figure 2, which shows the fraction of federal ownership for a sample of oil and gas wells in the Western United States where the Energy Information Administration has provided data on federal ownership. I find that 68% of these fields are in partial but not complete federal ownership.[2] This demonstrates that heterogeneous ownership and federal policy spillovers are likely to be important throughout much of the Western United States.

Spillover effects of policies from one plot to another are likely to be important because of how firms search for and learn about oil and gas. A firm usually is interested in a moderately large area for oil and gas development. Higher costs on one

[2]This figure increases to 91% when weighted by the area of the field.

plot affect willingness to drill on that plot, and may lead a firm to substitute to a different plot. Because firms update beliefs about the geology of the region from past drilling, such substitution means that costs on one plot can have long run effects on drilling and production outcomes on nearby plots.

2.3 The Natural Experiment

To identify how federal policy affects search, drilling, and production, I exploit a natural experiment that created exogenous variation in ownership.

Generally, analyzing the effect of federal land ownership is extremely difficult because federal land is not exogenously assigned. Land owned by the federal government tends to be more remote, more mountainous, and less agriculturally productive. These factors affect oil and gas profits directly, such that a comparison of outcomes on federal and non-federal land cannot identify how federal policy affects the oil and gas industry. Therefore it is important to use some kind of experiment where federal ownership status is not correlated with other factors that may affect oil and gas profits.

The United States Federal Government created such an experiment with the Land Ordinance of 1785. This policy specified rules for dividing land in newly acquired US territories, designating that certain exogenously-located plots of land would be transferred from the Federal Government to the governments of newly formed states. State governments then could use these lands to generate revenue through activities like oil and gas leasing.[3] In regions like southwest Wyoming that were too arid for settlement, the federal government retained ownership of the remaining land, leading to a persistent pattern of federal and state ownership.

The Land Ordinance of 1785 led to a an unusual pattern of federal and state ownership: Land was to be mapped into six mile by six mile squares called townships,

[3]Initially, such lands were usually designated to be sites for schools. However in later years, the sites instead were leased to generate revenue used to fund schools (Souder and Fairfax, 1996).

and subdivided into 36 square-mile plots called sections. Sections were numbered from 1 to 36 in a predetermined pattern, as shown in figure 1. The law specified that certain numbered sections would be transferred to state ownership at the time of statehood. In Wyoming, sections 16 and 36 were transferred to the State of Wyoming.[4] Figure 1 shows the resulting pattern of federal and state ownership.

This policy led led to variation in ownership and proximity to state land that is uncorrelated with geology. As section numbers were assigned exogenously, this assures that state versus federal land assignment is uncorrelated with geology. Similarly, the natural experiment led to some sections of federal land lying closer to state land than other sections. For example, figure 1 shows section 13 lies far from state land while section 15 lies close. This proximity is also exogenous—federal sections that are close to state land are not expected to have different geology than federal sections that are far from state land.

3 Modeling the search for oil and gas

Motivated by the spatial variation in the natural experiment, I propose a simple model to show how spatial patterns of environmental protection affect how a firm searches for oil and gas. The model illustrates how ownership and regulation affect search, learning, drilling and production. The model provides testable predictions about search, drilling, and production if federal land is costlier to operate on than state land.

The model is conceptually simple. The firm solves a dynamic well placement problem, deciding in each period where to drill. The firm is initially uncertain about the oil and gas reserves in the region. The firm learns about geology through drilling wells and observing reserves, updating its beliefs about oil and gas reserves on nearby

[4]Initially the law specified that section 16 would be transferred. Later when Wyoming became a state, both sections 16 and 36 were transferred. Some other states received either 3 or 4 sections depending on the date of statehood. See Souder and Fairfax (1996) for more details.

plots. Costs and drilling patterns in turn affect production. When federal environmental policies increase costs, the firm adjusts its drilling policy.

3.1 A simple two plot model

To keep the model tractable, I focus on a simple setting with only two plots. This two plot model maps intuitively to the natural experiment: The land assignment rule led to variation in federal versus state ownership, as well as variation in whether a given plot of federal land is close to or far from state land. To construct predictions for federal land that is far from state land, I use a two plot model where both plots are in federal ownership. To construct predictions for the case of state land and nearby federal land, I use a two plot model where plot 1 is in state ownership and plot 2 is in federal ownership. All proofs are in the Appendix.

3.1.1 Model set up

I assume that there is a single firm that is choosing where and when to drill. The firm can drill up to one well each on plot 1 and or plot 2. There are two time periods and the firm can drill in either $t = 1$ or $t = 2$. For simplicity, I assume no discounting.

Each plot has a fixed cost $C \in \{C_S, C_F\}$ that the firm must pay in order to satisfy environmental requirements and to drill. Because anecdotally, federal land is costlier to operate on, I assume that $C_F > C_S$.

Drilling on plot 1 allows the firm to extract reserves R_1 from plot 1; drilling on plot 2 allows the firm to extract reserves R_2 from plot 2. For simplicity, I assume that the firm immediately extracts any expected reserves at the time of drilling. There is no common pool—extracting from one plot does not deplete reserves on the other other plot. The value of reserves is normalized to 1.

Drilling also helps the firm learn about the geology of the region. The firm is initially uncertain about the true value of R_1 and R_2 but has an initial signal μ of

expected value: $E(R_1) = E(R_2) = \mu$, where the signal μ is drawn from a distribution with cdf $G(\cdot)$. The joint distribution of reserves $F(R_1, R_2|\mu)$ is symmetric, meaning that the two plots have identical distribution of reserves ex-ante. Drilling a well on plot i leads the firm to discover the true value R_i and update beliefs about the reserves on plot j with the conditional distribution $F_j(R_j|R_i, \mu)$.

I assume that higher signals μ and higher discovered reserves on one plot decrease the probability of low reserves on the other plot:

$$\frac{\partial F_i(R_i|\mu, R_{-i} = r)}{\partial \mu} < 0, \ \frac{\partial F_i(R_i|\mu, R_{-i} = r)}{\partial r} < 0 \ , \ \forall R_i, r, \mu \tag{1}$$

3.1.2 The Firm's Choices

In this setting, the firm has three choices:

1. The firm can drill an exploratory well on plot 1 first and then decide whether to drill plot 2, with expected profits:

$$\pi_1(\mu, C_1, C_2) \equiv \mu - C_1 + E_{R_1}[\max\{E_{R_2|R_1}(R_2|R_1) - C_2, 0\}] \tag{2}$$

2. Or the firm can drill an exploratory well on plot 2 and then decide whether to drill plot 1 with expected profits:

$$\pi_2(\mu, C_1, C_2) \equiv \mu - C_2 + E_{R_2}[\max\{E_{R_1|R_2}(R_1|R_2) - C_1, 0\}] \tag{3}$$

3. Finally, the firm may choose to not drill, yielding zero profits ($\pi_0 = 0$).[5]

[5] We can ignore other cases, such as where the firm drills both plots in the same time period, or cases where the firm waits until period 2 before drilling. All of these possibilities are dominated by $\max\{\pi_1, \pi_2\}$.

3.1.3 Exploratory drilling

- **Proposition 1:** The probability that a site has an exploratory well will be highest on state land, next highest on federal land *far* from state land, and lowest on federal land *close* to state land

In the case where plot 1 is state land and plot 2 is federal land, $\pi_1 > \pi_2$, so the firm will drill the initial exploratory well on state land and never drills exploratory wells on federal land. In addition, exploration rates are higher on state land because with lower costs, the firm is willing to drill with a lower signal μ. In contrast, the federal-federal case has medium exploratory drilling because the firm randomizes which plot it drills the exploratory well on conditional on the signal μ being high enough.

Here the predictions are especially sharp because as the two plots of land are perfect substitutes, a firm will never drill an exploratory well on federal land if it can drill on state land. In a more nuanced model, expected reserves may be higher on the federal plot such that the firm still sometimes drills an exploratory well on federal land in spite of the higher cost.

3.1.4 Any drilling

- **Proposition 2:** The probability that a site ever has drilling will be higher on state land than on federal land. It is ambiguous whether overall drilling will be higher on federal land close to or far from state land.

Ownership also affects the probability that drilling ever happens. A firm will only ever drill the second plot of land if after drilling the first plot, the firm believes expected reserves are higher than the fixed costs. Not all exploratory wells lead to a second well. Therefore state land will be more likely to ever have drilling relative to nearby federal land.

State land will also be more likely to ever have drilling relative to federal land in the federal-federal case. State land does not require as high of a μ to drill. Furthermore, conditional on μ being large enough for exploratory drilling, a given plot of federal land in the federal-federal case has less then a 100% probability of being drilled, because the firm may place the exploratory well on the other plot.

It is ambiguous whether federal land close to state land is more likely to ever have drilling relative to federal land far from state land. The probability of ever drilling on federal land in the state-federal case is:

$$\int_{\mu^*(S,F)}^{\infty} [1 - F_1(R_1^*(\mu, C_F))]\partial G(\mu) \tag{4}$$

While the probability of ever drilling on federal land in the federal-federal case is:

$$0.5 \cdot \int_{\mu^*(F,F)}^{\infty} \partial G(\mu) + 0.5 \cdot \int_{\mu^*(F,F)}^{\infty} [1 - F_1(R_E^*(\mu, C_F))]\partial G(\mu) \tag{5}$$

where $\mu^*(S, F) < \mu^*(F, F)$ gives the minimum μ required to justify drilling in the state-federal and federal-federal cases respectively, and R_E^* is the minimum reserves that need to be discovered on the initial exploratory well to justify drilling the second plot.

In comparing expressions 4 and 5, it is possible that federal land next to state land may have less overall drilling because it will never be the site of the exploratory well. But it may also have more overall drilling because as $\mu^*(S, F) < \mu^*(F, F)$, there is more likely to be exploratory drilling in the region in the state-federal case: If the probability that exploratory drilling happens increases significantly with state land ($G(\mu^*(F, F)) - G(\mu^*(S, F))$ is large) and the probability of drilling a second well is large, federal land close to state land may have more drilling than federal land far from state land.

3.1.5 Well level production

- **Proposition 3:** Wells on state land will have lower expected production relative to wells on federal land. It is ambiguous whether expected production will be higher for wells on federal land close to state land or for wells on federal land far from state land.

Costs affect production. Because the state-federal case has lower expected costs (and a lower μ^*), the firm is willing to drill exploratory wells in places with lower expected productivity. This will translate to lower expected well production for exploratory wells in the state-federal cases relative to exploratory wells in the federal-federal case. By lowering costs, the firm develops low productivity wells that would not have been drilled under higher costs.

Second, order of drilling affects production. For the first well drilled, the firm must believe that expected reserves plus the value of learning about the second plot are larger than the fixed costs. But for the second well drilled, there is no additional value in learning, and expected reserves need only cover costs. Firms will be willing to accept lower production for an exploratory well relative to a second well.

The cdf of production on an exploratory well is:

$$p(R_1 < r) = \frac{\int_{\mu^*}^{\infty} F(r|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} \partial G(\mu)} \tag{6}$$

The cdf of production on a second well drilled is:

$$p(R_2 < r) = \frac{\int_{\mu^*}^{\infty} \int_{R_E^*(C_F,\mu)}^{\infty} F(r|R_E,\mu)\partial F(R_E|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} \int_{R_E^*(C_F,\mu)}^{\infty} \partial F(R_E|\mu)\partial G(\mu)} \tag{7}$$

For any value of r, the expression in equation 6 is greater than the expression in equation 7.

As a result, wells on state land will have lower production relative to wells on nearby federal land because they are more likely to be exploratory. Similarly, wells on state land will have lower production relative to wells in the federal-federal case both because state land wells are more likely to be exploratory as well as because state land has a lower μ^*.

It is ambiguous whether federal wells in the federal-federal case will have higher or lower expected production relative to federal wells in the state-federal case. If secondary wells have much higher expected production than exploratory wells, then federal wells in the federal-federal case will have lower expected production because they are more likely to be exploratory. But if a lower μ^* in the state-federal case leads to new low-productivity wells on federal land, wells on federal land can have lower production than wells drilled in the federal-federal case. In this case, low costs on state land help the firm discover low productivity but still profitable fields that extend to nearby federal land.

3.1.6 Production per square mile

- **Proposition 4:** Expected production will be higher on state land rather than federal land. It is ambiguous whether federal land close to or far from state land will have higher expected production.

Because production requires drilling, places with higher probability of drilling will have higher expected production. State land will have higher expected production relative to federal land—both in the state-federal and federal-federal cases.

However it is not possible to predict whether federal land in the state-federal case or federal land in the federal-federal case will have higher production. This is because it is ambiguous whether proximity to state land will increase the probability of drilling and whether proximity to state land leads to higher expected well production.

3.2 Summary of Predictions and Mechanisms

The following list summarizes the propositions of the model, comparing state land (S), federal land close to state land (FC), and federal land far from state land (FF):

1. Probability of exploratory drilling: $S > FC$, $S > FF$, $FF > FC$
2. Probability of any drilling: $S > FC$, $S > FF$, FF (?) FC
3. Expected well production: $S < FC$, $S < FF$, FF (?) FC
4. Expected production per square mile: $S > FC$, $S > FF$, FF (?) FC

The model demonstrates three important mechanisms: A cost effect, a substitution effect, and a "threshold "effect.

- The **cost effect** is the fact that lowering costs on a plot increase willingness to drill. This leads to more drilling and lower expected production conditional on drilling
- The **substitution effect** is that having a low cost plot in a region shifts exploratory drilling from the high cost plots to the low cost plot. Shifting order of drilling also affects production, because exploratory wells tend to have lower production than secondary wells
- The **threshold effect** is the effect that overall profile of costs in the region have on the minimum signal required for drilling an exploratory well. The minimum expected reserve signal μ^* does not need to be as high in the state-federal case to justify exploratory drilling as it does in the federal-federal case. As drilling on places with lower signals leads to lower productivity wells, average well productivity will be lower on state land relative to the federal-federal case. This can potentially also lead to low productivity wells drilled on nearby federal land.

The model provides predictions and intuition that can be taken to the data. The model provides strong predictions about relative outcomes on federal versus state land if the costs of operating on federal land are higher. I compare outcomes on state and federal land to test whether the cost of operating on federal land is higher. The model is ambiguous about how proximity to state land affects drilling and production on federal land. In the empirical work, I test how proximity to state land affects outcomes on federal land and use the model to provide intuition on how to interpret the results.

While some modeling assumptions are strong for analytic tractability, it is fairly intuitive that the predictions will extend even when some assumptions are relaxed. For example, the model assumes that the firm has the same signal for both plots—which results in the stark prediction that there will be no exploratory drilling on federal land close to state land. If signals for each plot differ, we can have cases where a firm drills an exploratory well on federal land rather than on nearby state land because the signal on federal land was significantly higher. However, even in this more general case, lower costs on state land will still lead to more exploratory drilling, overall drilling, and production on state land.

In future work, I plan extend the model to a variety of other modeling assumptions. For example, federal policy may delay drilling rather than increase costs. Another issue is that there may be one or multiple firms searching for oil and gas in a local region. Future versions of this paper will address these issues.

4 Empirical Specification, Data, and Setting

In this section I describe how I take the model to the natural experiment, and describe the main empirical specification and inference. I also discuss the data and setting in Wyoming, showing why this setting is ideal for testing how federal ownership patterns

affect drilling and production.

4.1 Empirical Specification and Inference

My empirical specification explores how drilling and production outcomes vary as a function of whether land was assigned to be in state ownership (section 16 or 36) as well as whether land was close to or far from state-assigned land (proximity to the closest 16 or 36). Using the square mile section as the unit of observation, I use the regression specification:[6]

$$Y_i = \alpha + \beta \cdot 1_i(16/36) + \sum_{d \in \{1, \sqrt{2}, 2, \sqrt{5}\}} \beta_d \cdot 1_i(\text{closest } 16/36 \approx \text{d miles away}) \; + \; \varepsilon_i \quad (8)$$

Here, proximity d to the closest 16 or 36 section is measured as the distance between the section centroid and the centroid of the closest 16 or 36 section, as shown in figure 1. Because of the grid structure, sections may be 1, $\sqrt{2}$, 2, $\sqrt{5}$, or 3 miles from the closest 16 or 36 section. Here, 3 miles away is the omitted category. The dependent variable Y_i is the outcome of interest such as exploratory drilling or production.

Because outcomes on one section are correlated to outcomes on nearby sections, proper inference requires accounting for spatial correlation. I use Conley (1999) standard errors and assume that ε_i and ε_j may be correlated if section i and section j are within 20 miles of each other.[7] For most specifications, I use a uniform weight (as recommended by Conley (2008)), but use a Bartlett weight when the estimated variance-covariance matrix is not positive-definite (Newey and West, 1987).[8] I find

[6] I use the square mile section as the unit of observation because the policy rule specified ownership at the section level and because sections have well-defined exogenous boundaries.

[7] Using data I describe in subsubsection 4.2.3, I find that whether a section has ever had a productive well drilled predicts whether a nearby section has ever had a productive well drilled only if the sections are within 20 miles of each other (see figure 3).

[8] In inference, $\text{var}(\widehat{\beta}) = (\mathbf{x}'\mathbf{x})^{-1}\mathbf{x}'\Sigma\mathbf{x}(\mathbf{x}'\mathbf{x})^{-1}$. Because the true Σ is not observable, we approximate $\Sigma \approx \dfrac{N}{N-k} \cdot \widehat{\Sigma}$, where N is the number of observations and k is the number of parameters. With a uniform weight, each element $\widehat{\sigma_{ij}}$ of $\widehat{\Sigma}$ is $\widehat{\varepsilon_i}\widehat{\varepsilon_j}$ if the distance between i and j is less than 20

that the two weighting methods lead to similar variance-covariance matrices.

4.2 Setting

To test model predictions, I use data from the Greater Green River Basin (GGR) of Wyoming—a geological region in Southwest Wyoming. Figure 4 is a map of the GGR. The GGR is a useful region to study because of data in Wyoming, the persistence of the federal-state ownership pattern, lack of confounding factors, relatively high oil and gas productivity, and no common pools.

4.2.1 Oil and gas productivity

One reason to focus on the GGR is that it is a very productive natural gas region, with significant oil reserves as well. The GGR has 12 of the 100 largest natural gas fields in the US, and 2 of the 100 largest oil fields (Energy Information Agency, 2010). This productivity is reflected in my data: I find 22% of square-mile sections have had drilling by 2010, 10% have had exploratory (or "wildcat ") wells, and that 14% of sections have had a productive oil or gas well (Table 1). There has been extensive drilling in the area—98% of sections lie within 6 miles of a well. This extensive drilling means that there are relatively few fields that have been discovered recently, with most fields discovered between 1955 and 1995 (Figure 5).

4.2.2 Lack of common pools

Another reason to focus on the GGR is that there is little evidence of common pools. If common pools exist, production from one well can be affected by drilling and production of nearby wells–meaning that observed production is not a good proxy for geological productivity. However common pools are unlikely in this setting. Many

miles, and zero otherwise. With Bartlett weights, σ_{ij} is $1(d_{ij} \leq 20) \cdot \frac{20 - d(i,j)}{20} \cdot \widehat{\varepsilon}_i \widehat{\varepsilon}_j$, where $d(i,j)$ is the distance in miles between sections i and j.

of the oil and gas wells in the region are in relatively impermeable geological areas, meaning that oil and gas cannot flow long distances underground (Nelson, Ewald, Santus, and Trainor, 2009). Furthermore, Wyoming policy restricts how closely wells can be drilled to each other. As a result, it is unlikely that one well can significantly affect production on nearby wells. While firm data is limited, Figure 6 shows that more than half of fields have only one operating firm, and less than 10% have more than 3 operating firms, which further decreases the possibility of common pools distorting production. I discuss this issue more in subsection 6.2, where I test whether decline curves are consistent with common pools.

4.2.3 Data Quality

I compile data on drilling, and production, as well as federal and state oil and gas leases. Drilling data date back to 1900. Federal and state leases date back to the 1800's. Production data date back to 1978, and are particularly useful because Wyoming tracks production at the well level rather than the lease level.[9] I also compile detailed GIS data on state, federal, and private mineral ownership, as well as a number of other geographic features. By compiling comprehensive data from leasing to production, this paper paints a more complete picture of how ownership and policy have affected oil and gas development over space and time.

4.2.4 Robustness of ownership pattern

A fourth reason to focus on the Greater Green River basin is that the original federal-state ownership pattern has remained relatively robust. As this part of Wyoming is arid, there has been little private demand for the land. There have also been few transfers between federal and state land. I exclude the part of the GGR within 20.5 miles of the transcontinental railroad because much of this land was transferred to the

[9]Some other states, like Texas, only require reporting production at the lease level which complicates analysis because leases vary significantly in area and number of wells.

Union Pacific Railroad (Kunce, Gerking, and Morgan, 2002). I also exclude sections that are on the border with Utah and that are more than 3.2 miles away from the closest 16/36 section in Wyoming. This leaves a sample of 12,549 sections, with 696 sections that are numbered either 16 or 36.

Within this sample, whether a section is 16 or 36 is a strong predictor of current mineral ownership. Figure 7 is a map of ownership within part of the GGR that shows that the ownership pattern is fairly strong. To quantify the strength of the ownership pattern, I construct a measure of the fraction of the section that is in state or federal mineral ownership. In Table 3 I regress this measure on location and distance indicators. I find that a non-16/36 section is only about 2% state mineral lands on average, while a 16/36 section is on average 80% in state ownership. In contrast, a non-16/36 section tends to be 90% in federal ownership, while a 16/36 section is on average only 18% in federal ownership. This is driven largely by sections either being almost completely in state or almost completely in federal ownership.

Crucially, these regressions also show that ownership does not change as a function of distance away from state land. In the second-to-last row of Table 3, the F test fails to reject the hypothesis that coefficients on 1 mile, $\sqrt{2}$ miles, 2 miles, and $\sqrt{5}$ miles are not all equal to zero.

4.2.5 Testing the exclusion restriction

Finally, the GGR is a useful place to study because there is little evidence that above-ground factors are correlated with ownership patterns. We might be concerned if physical characteristics by chance were correlated with ownership, or if ownership patterns led to other changes in economic or social outcomes that also affect oil and gas development. However, I find that this is not the case. Using the regression specification from equation 8, Table 4 shows that physical characteristics are not strongly correlated with 16/36 sections and proximity to 16/36 sections. Similarly,

Table 5 examines social and economic outcomes like settlements and fences and finds very little evidence that such outcomes have been correlated with 16/36 sections and proximity to 16/36 sections.[10] In drilling regressions, I include robustness checks where I control for these above-ground factors, and find that they have very little effect on coefficients.

5 Empirical Results

5.1 Exploratory wells

First, I examine exploratory wells. Firms report whether a well is part of a known producing field or if the well is a "wildcat "well—one drilled in an area prior to there being any known oil or gas field. I regress an indicator for whether wildcat wells have ever been drilled on 16/36 sections and proximity to 16/36 sections using the specification of equation 8, with results in columns 1 and 2 of Table 6. As predicted by theory, 16/36 sections are more likely to have exploratory drilling—14.1% of 16/36 sections have wildcat wells, relative to only nearly 10.9% of sections 3 miles away, a difference that is significant at the 5% level. Non-16/36 sections that are closer to 16/36 sections are even less likely to have exploratory drilling than sections 3 miles away. The hypothesis that coefficients for 1-$\sqrt{5}$ miles are all equal to zero is rejected at the 5% level. Column 2 shows that results are robust to adding controls for local geographic characteristics.[11]

The results demonstrate how firms substitute in the exploration decision: Higher costs on federal land lead firms to substitute to state land. Federal land

[10] These regressions do not include information on roads because in many cases roads were built by oil and gas firms.

[11] Because wildcat wells may be relisted as part of a field if they led to a discovery, I construct an alternative measure of exploratory drilling where I also include consider a section to be the site of an exploratory well if there is a well on the section that was drilled in the first year of all wells within that oil or gas field. I find quantitatively similar results. Results available upon request.

that is far from state land has higher exploratory rates than federal land close to state land. This evidence suggests that costs on federal land are lower than on state and that firms shift exploratory drilling to low cost plots.

5.2 Overall drilling

The model also predicts that overall drilling will be higher on state land but is ambiguous about whether proximity to state land increases or decreases drilling on federal land. I construct a measure of whether drilling has ever happened on a section by 2010. I find that drilling is highest on state land and that proximity to state land leads to a long run decrease in drilling on federal land. Columns 3 and 4 of table 6 show that 16/36 sections have a 26.7% probability of ever having drilling which is higher than drilling rates on non-16/36 sections. The difference between 16/36 sections and non-16/36 sections is statistically significant with the exception of 3 miles away. Proximity to state land decreases drilling on federal land: For example, I find that sections 3 miles away have a 24.7% probability of ever having drilling, while sections 1 mile away have only a 22.1% probability of being drilled.

The productivity of exploratory wells explains why the short run substitution in exploration leads to long run differences in overall drilling patterns. Most exploratory wells are not productive and do not lead to additional drilling. I find that 26% of wildcat wells are reported as productive, whereas 84% of non-wildcat wells are productive. Furthermore, nearly half of all sections that ever get drilled are wildcat drilling sites. By shifting exploration from federal land to state land, federal land overall increases a significant decrease in drilling. The fact that state land leads to a lower threshold μ^* required for drilling is not enough to counteract this substitution effect (see equations 4 and 5).

Because exploratory wells are less likely to be productive relative to non-exploratory wells, places that have more exploratory drilling are also places that tend

to have a lower likelihood of having a productive well—conditional on drilling. I explore this in columns 1 and 2 of Table 7 where the dependent variable is whether a section has ever had a productive well drilled, conditional on drilling ever happening. I find that sections 3 miles from the closest 16/36 section—federal land far from state land where exploratory drilling is higher—have a 60.6% probability of having a productive well conditional on drilling, while sections $\sqrt{2}$ miles away—federal land close to state land where exploratory drilling is lower—have a 64.4% probability of having a productive well conditional on drilling. Because of the small sample size, the coefficients for sections 1-$\sqrt{5}$ miles are not individually significantly different from zero, though they are jointly significant from zero at the 10% level.

I also find the even though state land is most likely to have exploratory drilling, it is also most likely to have productive drilling conditional on any drilling. Columns 1 and 2 of Table 7 also show additional evidence that the cost of operating on state land is lower. There is a 67.8% probability that a 16/36 section with drilling ends up being productive, in contrast with only a 60.6% probability for sections 3 miles away with drilling. This suggests that lower costs state land allows firms to develop wells with low productivity.

5.3 Well productivity

Next I examine how ownership affects productivity of wells. Low costs on state land imply that firms should be willing to drill lower productivity wells that would not be drilled on federal land. It is ambiguous whether proximity to state land will increase or decrease the productivity of wells on federal land.

To examine production, I compile monthly well-level production for 1978-2012. Production includes measures of natural gas—measured in thousands of cubic feet (mcf), and oil—measured in barrels.[12] To aggregate production, I use a barrel-of-oil

[12]Some natural gas wells produce natural gas liquids. These have a value similar to oil and can

equivalent production (BOE) measure, where 6 mcf of natural gas has approximately the same energy content as one barrel of oil. Because I do not observe future production, I proxy for total well productivity with the first 12, 24, or 36 months of production.[13]

Using this measure of production, I find that wells on state land have significantly lower productivity. I also find that producing wells on federal land tend to have lower production if close to state land. Column 1 of Table 8 shows that the average producing well on 16/36 sections has only about 62% of the BOE productivity of an average producing well on a section 3 miles away. Wells close to state land also have lower production—an average producing well on sections 1 mile from the closest 16/36 section have on average 78% of the production of a well 3 miles away. Similar numbers hold for gas (columns 4-6) and oil (columns 7-9). The assumption that production at a given age of the well is proportional to total production seems to hold, as coefficient estimates are very similar whether measuring production as the first 12, 24, or 36 months. While coefficients for 1-$\sqrt{5}$ miles are mostly statistically significant, coefficients for 16/36 sections are imprecisely estimated. However, in the Appendix I show that the coefficients are similar and more precise when controlling for field fixed effects and drilling date fixed effects. I also show that the results are similar when excluding outliers.

Well productivity regressions show that lower costs on state land lead firms to drill with lower expected productivity, which translates into lower expected production. Lower productivity discoveries on state land inform the firm about low

be measured in barrels. While firms may report natural gas liquids in either the natural gas or oil category, I find that most natural gas wells report some oil production, which suggests that natural gas liquids are reported as oil.

[13] Oil and gas production is often modeled by geologists as following the form $q_i(a) = f(a)q_i$, where a is the age of well i (Arps, 1945). Under this assumption, aggregate productivity over any subset of the well life time will be proportional to total well productivity. This assumption seems to be valid because other research has found that production is unresponsive to price changes (Anderson, Kellogg, and Salant, 2014). In addition, prices for natural gas have only been deregulated fairly recently.

productivity but profitable potential wells on nearby federal land, which lowers average well productivity of federal wells that are close to state land. It is important to note that these are selection effects—state land and proximity to state land does not decrease productivity, but rather affect what kinds of wells are drilled on these lands—and what kind are not.

5.4 Overall section level productivity

Finally, I find that ownership affects production per square mile with higher production on state land and federal land that is far from state land. In Table 9, I aggregate total production for all wells within a section drilled in 1980 or later, and compute total well productivity for all wells within a section. I use the MacKinnon-Magee transformation for production to reduce outliers yet keep zeros (MacKinnon and Magee, 1990).[14] I find that proximity to state land decreases production. For example, in column 1, I find that barrel-of-oil equivalent production for sections 1 mile from the closest 16/36 is about 77% that of production for sections 3 miles from the closest 16/36 section and is statistically significant at the 10% level. Similar results hold for gas and oil, as well as both with and without township fixed effects. I also find that 16/36 sections have higher production unconditional on drilling relative to other land, although the difference between 16/36 sections and sections 3 miles away is not statistically significant.

I find similar results when examining whether a productive well has ever been drilled. Table 7 columns 3 and 4 examine whether a productive well is ever drilled within a section. I find that sections 3 miles away have a 15.0% probability of ever having productive drilling, while 16/36 sections have a 18.1% probability of ever having productive drilling—a 20.1% increase. Number of wells drilled is also higher

[14] The MacKinnon Magee transformation constructs a transformed dependent variable $\tilde{q} = \log(q + \sqrt{q^2 + 1})$.

on state land, though not significantly so (columns 5 and 6 of Table 7). These productivity results also suggest that proximity to state land decreases productivity, though the pattern is not statistically significant.

How ownership and proximity to state land affect production can be seen in Figure 8, where I graph the distribution of production, unconditional on drilling, comparing 16/36 sections, sections 1-$\sqrt{5}$ miles away, and sections 3 miles away from the closest 16/36. The graph shows that ownership has little effect on high return plots. Each category of land has about equal probability of being a section that produced more than 1,000,000 BOE from 1978-2010.[15] However ownership affects productivity for lower productivity sections. In particular, the cdf for 16/36 rises much more steeply than the cdf for 3 miles, which shows that 16/36 sections are better at drilling and producing under low productivity. At the low end of the cdf, the cdf for sections 1-$\sqrt{5}$ miles away is much higher than that of 3 miles and of 16/36 sections, because learning on from state land means that low productivity federal sections will not be drilled.

5.5 Changing policies over time

Finally, I explore drilling patterns over time to see how policy changes affect revealed search patterns. Many of the environmental policies affecting federal land were implemented in the 1970's. If these changing policies increased the cost of drilling on federal land, we would expect to see greater substitution to state land after the 1970's.

In figure 9 compares the rollout of drilling on 16/36 sections, sections that are 1-$\sqrt{5}$ miles away, and sections that are 3 miles away. The regression version of this figure is in Table 10. I find that each of these types of sections have fairly similar probabilities of being drilled by up until about 1980. After the 1980's, drilling on sections 1-$\sqrt{5}$ miles away diverges from rates on 16/36 sections. However, drilling

[15] In Figure **??**, 1,000,000 BOE is approximately the point where the x axis is 14.

rates on sections 3 miles away did not diverge very much from 16/36 sections until the mid 2000's.

Similar results are shown for the location of wildcat drilling. In Figure 10 looks at the number of wildcat wells drilled on 16/36 sections and sections 1 mile away. Under homogenous policies, there should be a 4:1 ratio of wildcats on sections 1 mile away to wildcats drilled on 16/36 sections. I find that while the ratio is noisy, by the 1980's there is a sharp decrease in the ratio.

However, it is not totally clear what policy changes led to this divergence in drilling patterns. An alternative explanation is changing leasing policies: In 1980, the State of Wyoming changed how it allocated leases, switching from a first-come first-serve system to an auction system. Because under the auction the State of Wyoming published a catalog of all lands available to lease, this may have increased awareness of state leasing opportunities and in turn increased drilling. This is a topic of future research.

6 Ruling out Alternative Mechanisms

Revealed drilling and production outcomes show that ownership patterns have a significant effect on the oil and gas industry. Drilling and production outcomes are consistent with a model of search and learning where the cost of operating on federal land is higher. We might be concerned if the federal government withheld leases—such that drilling on federal land was lower simply because the federal government was not willing to offer leases. We might also be concerned if production outcomes on one section of land distort production on nearby land. I address each of these concerns in turn.

6.1 Irregular Leasing Policies

To examine whether the federal or state governments used irregular leasing policies, I digitize federal and state oil and gas leases. Federal oil and gas leases records are taken from the Bureau of Land Management website, with more recent leases also on the BLM's LR2000 database.[16] State oil and gas lease records were digitized from paper records at the Wyoming State Lands office in Cheyenne, Wyoming. Lease data date back to the 1800's. I digitize lease records for 11,091 out of the 12,549 sections in my sample. I exclude sections in townships with significant private land or with very little oil and gas drilling.

I find that a very high fraction of sections have reported leasing: Table 11 shows that 98.9% of sections of land ever had a federal or state oil and gas lease on it. Both federal and state governments have been very likely to issue leases: 98.7% of non-16/36 sections had a federal oil and gas lease on them, and more than 99% of 16/36 sections with state land had a state oil and gas lease on them.

One concern is that federal land was slow to be drilled because federal land was slow to be leased. However Figure 11 shows that the opposite occurred—federal land tended to be leased long before state land. I plot the rollout of the first lease for each section over time—conditional on a lease being offered. I find that federal leasing tended to happen before state leasing: More than half of federal leases were issued by 1940, while it wasnt until about 1980 that 50% of state leases had been issued.

Another concern is that though the federal government initially leased much of the land, it began withholding certain plots from leasing later on. Indeed, I find that only 28.1% of non-16/36 sections currently have a federal oil and gas lease on them, and that only 17.7% of non-16/36 sections that have never had drilling currently have

[16] Lease records are taken from `http://www.wy.blm.gov/mtps/search.php`. Additional information about leases is taken from `http://www.blm.gov/lr2000/` .

a federal oil and gas lease on them. If the federal government has restricted leasing on these places, this could explain the lack of drilling on federal land.

However this change is likely driven by the nomination process. In earlier years, federal leases were offered everywhere, and the US government had a policy to issue leases on all Bureau of Land Management land. Later, the Federal Oil and Gas Leasing Reform Act of 1987 required firms or other parties to first nominate land to be offered as oil and gas leases before the Federal Government would offer leases through the auction process. Because the nomination process was costless, it likely only restricted extremely low expected productivity plots from being offered. As a result, many of the places that not considered good oil and gas sites were not nominated after 1987. For example, I find that for non-16/36 sections that have never had drilling, 45.2% of them have a lease if the closest 16/36 section has a productive oil or gas well. However only 14.8% have leasing if the closest 16/36 section does not have a productive oil or gas well.

Even with nomination, we might still be concerned that federal land that was nominated may still have been withheld from the auction. The major reason why certain nominated lands are not auctioned is if an environmental organization protests auctioning the plot on environmental grounds. While comprehensive data on protests are not available, recent data suggests that the vast majority of nominated leases are auctioned.[17] Rather than withhold plots from auction, the BLM appears to lease these lands but impose stricter environmental stipulations for the lessee.

Figure 11 suggests another concern: That increased drilling on state land after the 1980's was driven by an increased willingness of the state government to issue leases. However this also does not appear to be the case. Lower rates of leasing prior

[17]For example, the February 2013 Wyoming BLM auction offered 162 leases, 14 of which were protested by the Biodiversity Conservation Alliance and Western Resource Advocates. The BLM rejected all 14 of these protests and offered all 162 parcels in the auction. Records from other dates available at `http://www.blm.gov/wy/st/en/programs/energy/Oil_and_Gas/Leasing/historical_index.html`.

to the 1980's appear to be driven by the fact that a firm had to request a lease before it was offered and no comprehensive list of lands that could be leased was listed. Starting in 1980, Wyoming switched to an auction system and began offering a more comprehensive list of sites to be auctioned. Greater awareness of possible leasing opportunities likely drove the increase in state leasing

Overall, I do not find evidence that drilling patterns are driven by irregular leasing policies. Future work will also explore the role of other changes in federal and state policies such as royalties and rental rates. However these are unlikely because firms anecdotally report that environmental compliance costs are the major reason for lower willingness to operate on federal land.

6.2 Common Pools

Another concern in interpreting the results is common pools. The model assumes that the firm cannot manipulate production. In particular, I assume that a well on one section of land cannot distort production for a well on a nearby section. I also assume that that the firm'signal μ is a noisy signal of true reserves under the plot. This allows me to use production outcomes to make inference about signals. But if production from one well can decrease production from another well in the same field, such inference may be biased. However the geology of the region and well spacing rules make such common pools unlikely.

6.2.1 Well spacing and geology

A major reason that common pools are unlikely to exist in this region is well spacing rules. Well spacing rules are requirements that limit how closely a well can be drilled to another well. Another reason is the permeability of the underlying oil or gas reservoir. If permeability is low, oil and gas cannot flow long distances underground. Here I discuss well spacing rules, showing that in the Greater Green River basin

wells are spaced far enough apart relative to the permeability of the region such that common pools are very unlikely.

Well spacing rules originated from early oil extraction experiences in the 1800's and early 1900's in states like Pennsylvania, Texas, and California, where the high density of wells led to inefficient extraction and common pool problems (Libecap and Wiggins, 1984). In response to this problem, a coalition of states formed the Interstate Oil Compact Commission (IOCC) in 1935 which advocated well spacing guidelines in order to eliminate common pool problems (Interstate Oil and Gas Compact Commission, 2006). Today all oil and gas producing states in the United States—and many foreign countries—have adopted well spacing rules. As a result, common pools are unlikely to be a concern for onshore oil and gas production in the United States.

In the case of Wyoming, the Wyoming Oil and Gas Conservation Commission (WOGCC) has established location-specific well spacing rules. For most of the Greater Green River basin, there can only be up to 4 wells drilled in a section—one in each quarter section, where a quarter section measures 0.5 by 0.5 miles (or 160 acres). In some cases, especially with oil, there may one well every quarter-quarter section (or 0.25 by 0.25 mile unit of 40 acres). For each case, wells must be drilled near the center of the quarter or quarter-quarter. This assures that multiple wells do not drain the same area.[18]

Furthermore, most of the fields in the Greater Green River basin have low permeability such that oil and gas cannot flow long distances. This can be seen in Figure 12, where I graph permeability from a number of wells. These data are taken from the 1979 and 1992 editions of the Wyoming Oil and Gas Fields Symposium (Wyoming Geological Association, 1979, 1992). The distribution of permeability in Figure 12 shows that permeability for most wells ranges from 0.1 millidarcys to 100 millidarcys. This is in the low range of permeability for conventional oil and gas

[18]Spacing rules for wells are described at `http://soswy.state.wy.us/Rules/RULES/7928.pdf`.

fields (see for example Bear (1972), page 136). This range of permeability leads to relatively small drainage areas. For example, the Hogsback Field, which has an estimated permeability of 26.5 milidarcys, has an estimated drainage area of 37.3 acres—just smaller than the 40 acres of a quarter-quarter section. The Bunker Hill field, which has an estimated permeability of 94 milidarcys, has a drainage area of 39.3 acres.[19] With low permeability and sufficient well spacing, two wells cannot affect each other's production even if they technically lie in the same reservoir.

6.2.2 Testing for common pools

Given the geology and spacing rules of the region, common pools are unlikely. However to test for common pools, I explore decline curves in different regions. Because well production tends to decline faster under common pools, regions with more likelihood of common pools are likely to have steeper declines in production.

Common pools are least likely to happen on federal land because of a policy called unitization. Under unitization, when there are multiple firms all extracting from the same field on federal land, the federal government can impose that production is managed under a single operator, effectively operating the land as a single firm (Libecap and Wiggins, 1985). However there is no authority to impose unitization for operations spanning federal and non-federal land. Therefore we might expect that common pool problems are more likely for wells on state land and federal land close to state land.

This is potentially a concern because it gives an alternative interpretation to well productivity results: Production regressions in table 8 suggest that low costs on state land lead to low productivity wells drilled on state land and federal land close to state land. An alternative explanation for this phenomenon is that low production on and near state land is driven by common pools. If wells on state land and nearby

[19] Drainage areas are taken from `wogcc.state.wy.us`, from dockets 169-09 and 415-08.

federal land are extracting from the same reservoirs, and if there is no centralized operator, this could lead to fast initial extraction and fast declines in production.

To test for common pools, I construct a measure of decline from the first year to the second year.[20] Results are in Table 12. I find that decline rates are not higher for sections on or close to state land. This suggests that common pools are not driving production results.

7 Cost estimates and other policy implications

In this section I give back-of-the-envelope estimates of costs and discuss challenges of identifying costs in this setting. I also discuss some of the policy implications of this research, including the challenges of difficulty of regulation under leakage, allocative inefficiency, and the spatial extent of policy spillovers.

7.1 Cost estimation

I provide a back-of-the-envelope estimate of costs both on state and federal land based on revealed drilling and production. The estimated costs include drilling costs, the costs of other well-level infrastructure such as building an access road, as well as the costs of meeting regulatory and bureaucratic requirements. A measure of the additional regulatory burden of federal land is taken by subtracting estimated state costs from estimated federal costs, as infrastructure and drilling costs should be similar between the two.

I identify costs using the structural assumption that a well will only be drilled if expected revenue exceeds costs. Costs are identified because for a given level of expected revenue, the probability that a well is drilled is the probability that the cost is less than expected revenue. I allow costs to be heterogeneous because the

[20] The dependent variable is $\log(y_2) - \log(y_1)$ where y_1 and y_2 are total production in the first and second year of production, respectively.

environmental compliance measures required by the BLM are determined on a case-by-case basis.

To construct a measure of expected revenue, I examine square mile sections of land where at least one producing well was drilled with production R_1. This becomes the basis for calculating expected production on a second well drilled within a section $E(R_2|R_1)$. Expected profits for the second well are:

$$\pi = (1-\tau)PE(R_2|R_1) - C$$

where τ is aggregate taxes and royalties, and P is the expected price. Then the probability of drilling a second well identifies the cdf of costs:

$$\text{prob[drill well 2]} = \text{prob}[C \leq (1-\tau)PE(R_2|R_1)]$$

By regressing an indicator of whether the second well is drilled on the measure of expected revenue, I identify the cost. The median cost is identified from the level of expected revenue where the probability of drilling a second well is 50%. I use both a probit and a non-parametric specification to estimate the median cost. I discuss the details of this estimation in the appendix.

Figure 13 shows the estimated cdf of costs for non-16/36 sections. For non-16/36 sections, I estimate a median cost of \$19.1 million dollars (2010). The estimate from the non-parametric specification is very similar. The bootstrapped 95% confidence interval from the probit specification ranges from \$13.9 to \$25.8 million dollars.

Figure 14 shows the estimated cdf of costs for 16/36 sections. Here, I estimate a median cost of \$1.9 million dollars.[21] This estimate is very similar to engineering estimates of drilling costs, which averaged about \$1.1 million dollars (in 2010 dollars)

[21] Here I exclude one outlier that had very high expected revenue but no second well drilled. Including the outlier gives an estimated costs of \$0.2 million dollars

over the period from 1980 to 2007 [22]. Because the number of observations is small the estimate of the median cost is very imprecisely estimated, with the bootstrapped 95% confidence interval ranging from less than one dollar to more than a quadrillion dollars.

The difference in the point estimates of costs suggests that federal regulation increase costs by about \$17 million dollars. Because costs on 16/36 sections are so imprecisely estimated, the difference in median costs between 16/36 and non-16/36 sections is also imprecisely estimated and not significantly different from zero.

7.2 Caveats to cost estimation

This cost estimate of \$19.1 million dollars is likely an upper bound because of the standard selection problem, where I do not observe the counterfactual of expected production for second wells that were not drilled. As the firm also has unobservable geological signals of productivity, this suggests that $E(R_2|R_1, 2 \text{ drilled}) > E(R_2|R_1, 2 \text{ not drilled})$. Using the regression estimate to predict $E(R_2|R_1)$ will overstate the returns to drilling second wells that were not drilled and will overstate costs.

Measurement error of the true expected productivity is also a concern and could bias cost estimates either up or down. Estimated expected production $E(R_2|R_1)$ is a mismeasurement of the firms true expected production because the firm has additional geological information not observable to the econometrician. Without making additional assumptions, it is not possible to separately identify costs from measurement error. To see this, suppose that estimated $E(R_2|R_1)$ is low but the firm still drills the second well. We cannot distinguish whether this is due to a high geological signal or a low draw from the cost distribution. Measurement error will tend to suggest a cost distribution with a larger variance than the true cost distribution. Measurement error may also bias the estimated median cost if either measurement

[22] Drilling cost estimates taken from `http://www.eia.gov/dnav/pet/pet_crd_wellcost_s1_a.htm`

error is asymmetric or if the true cost distribution is asymmetric.

There are a number of other caveats that may bias cost estimates. Costs will be overstated if drilling the second well also provides value through additional geological information about the region. This is unlikely to be important because the second well drilled within a section will likely provide little additional geological information. Another concern is that the estimate does not account for marginal costs such as the cost of transporting the oil and gas to the seller. This is not likely to be a concern since marginal costs are likely very low, especially with natural gas.A third concern is that these estimates do not allow for endogenous costs, where the regulator may adjust environmental requirements in view of expected production.

Future work will explore the extent to which costs can be at least partially identified. While selection is a significant issue, Manski (1989) shows how parameters can be sometimes at least partially identified under selection. Incorporating geological data may help to provide a more precise estimate of expected production, although it is unlikely that any econometric approach can recover the geologists precise expected production. Further identification can come from the decision of whether to drill an initial exploratory well as well as from production from wells on other nearby sections. A major challenge, however, is that firms have complicated prior beliefs about the joint distribution of reserves over multiple potential drilling sites. This large unobservable state space is a significant obstacle to identification.

7.3 Spillovers

Drilling and production regressions suggest suggest that local policies in one place can have relatively long ranging spillovers. In this empirical work, the difference between outcomes on sections $\sqrt{5}$ miles from state land and sections 3 miles from state land suggests that low costs on state land affect drilling outcomes for plots at least $\sqrt{5}$ miles away from state land. The spillover range of $\sqrt{5}$ miles is a lower bound—it

is possible that firms are even shifting exploratory drilling activity from sections 3 miles from state land to state land. The fact that policies can range further is not surprising given that productive wells on one location predict productive wells up to 20 miles away (as shown in figure 3).

The two types of spillovers—the substitution effect and the signal threshold—also have implications for calculating counterfactuals. Consider the counterfactual for average drilling rates if federal costs were reduced to state levels. The currently observed rate of drilling on state land may be an upper bound under the substitution effect, because firms will not substitute from higher cost federal land if there is no federal land. However rates of drilling on state land may be a lower bound if lowering costs on federal land decreased total firm costs, such that more low-signal plots were drilled on state land.

Similarly, the counterfactual for outcomes if all land was under federal ownership is difficult to calculate. Raising costs on state land to federal levels would lead to more drilling because firms would not substitute to state land. However it would decrease drilling by increasing the minimum threshold signal that a firm needs to drill.

7.4 Incomplete Regulation and Leakage

One of the challenges of implementing environmental protections on federal land is that nearby non-federal land is not regulated and firms can re-located drilling activity to non-regulated land. Such leakage and incomplete regulation has been explored in other settings, including Fowlie (2010) and Holland (2012). In this setting, exploration on one plot is a substitute for exploration on another plot, and an environmental tax on the regulated plot will shift exploration to the non-regulated plot.

However, learning adds a twist because the firm then uses geological information from drilling on the unregulated plot to update beliefs about reserves under the

regulated plot. Leakage delays drilling on the regulated plot, but learning allows the firm to develop a more precise signal about the reserves on the regulated plot. Such learning means that in extreme cases, partial environmental regulation will shift the order that plots are drilled, but have no effect on the expected number of wells that are drilled. (In the appendix I show a simple 2-plot example where imposing higher costs on federally-owned land decreases drilling on federal land but has no effect on the expected number of wells because of learning spillovers from non-federal land to federal land).

8 Conclusion

In this paper I examine how federal regulation affects the search for and production of oil and gas on both federal and non-federal lands. I highlight the interaction between spatially heterogeneous land management and how firms learn about geology through drilling. Using a natural experiment with exogenously located federal and state land, I find that drilling and production are relatively low on federal land, suggesting that the costs of drilling on federal land are relatively high. I find that proximity to low cost land leads to long run decreases in drilling and production on nearby high cost land, even though proximity to low cost land also helps firms develop a more precise signal about the returns to drilling on high cost land. I show that drilling and production patterns are not explained by irregular leasing policies or by common pools. A simple back-of-the-envelope calculation estimates that federal regulation costs about $17 million dollars per well.

While this paper focuses on Wyoming, preliminary work shows that state costs are relatively low in other places. I have compiled data from Montana, Colorado, Utah, and New Mexico—states where the original state land assignment from the Land Ordinance of 1785 has remained relatively robust, and where there is significant

oil and gas drilling, and relatively high quality oil and gas well data. I find that the number of wells located on lands designated for state ownership through the Land Ordinance of 1785 is significantly higher than would be predicted if well location was uncorrelated with section numbering.[23] These results suggest that heterogeneous ownership and policies are likely to have spillover and leakage effects in a variety of settings.

This work suggests avenues for further research. One particular challenge is to estimate a more complete structural model that builds on the back-of-the-envelope cost estimation. Further identification can come from adding additional information such as production outcomes from other wells. An important challenge in structural estimation is to account for the firm's priors about the joint distribution of reserves over multiple well sites, and how the firm updates its geological beliefs through each well drilled. Ideally, such structural estimation could be used not only to identify costs, but also to identify the firm's priors and the value of information from drilling exploratory wells. With these parameters identified, it would then be possible to simulate important counterfactuals, such as drilling and production outcomes under homogenous all-state or all-federal ownership.

[23]In Colorado and Montana, I find that 6.3% and 6.0% of wells are on 16/36 sections, compared to a predicted fraction of 5.6%. In Wyoming, the fraction of wells on 16/36 sections is 6.5%. In New Mexico and Utah, where sections 2, 16, 32, and 36 were initially allocated to state ownership, I find that 11.9% and 12.4% of wells are on these sections, compared to a predicted fraction of 11.1%. Treating each of these 5 states as an observation, I reject at the 5% level that the predicted fraction of wells on lands allocated for state ownership is equal to the observed fraction.

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10 Tables

	mean	st.dev.	median	5th perc	95th perc
16 or 36	0.06	0.23	0.00	0.00	1.00
distance to closest 16 or 36	1.63	0.68	1.67	0.00	2.90
square miles	0.98	0.11	1.00	0.91	1.02
fraction state mineral	0.06	0.22	0.00	0.00	0.69
fraction federal mineral	0.86	0.29	1.00	0.01	1.00
had wildcat well by 2010	0.10	0.30	0.00	0.00	1.00
had any well by 2010	0.22	0.42	0.00	0.00	1.00
had any productive well by 2010	0.14	0.35	0.00	0.00	1.00

Table 1: Summary statistics for sections.

	mean	st.dev.	median	5th perc	95th perc
on 1636	0.07	0.25	0.00	0.00	1.00
oil well	0.10	0.30	0.00	0.00	1.00
gas well	0.64	0.48	1.00	0.00	1.00
oil and gas	0.01	0.10	0.00	0.00	0.00
dry or unreported	0.22	0.42	0.00	0.00	1.00
wildcat	0.12	0.32	0.00	0.00	1.00
drill year	1988.06	23.27	1998.00	1937.00	2010.00

Table 2: Summary statistics for wells.

	(1) State	(2) State	(3) Fed	(4) Fed
is 16/36	0.781***	0.781***	-0.727***	-0.715***
	(0.067)	(0.067)	(0.070)	(0.071)
$\approx$ 1 mile away		0.004		0.011
		(0.004)		(0.009)
$\approx \sqrt{2}$ miles away		-0.001		0.017
		(0.004)		(0.011)
$\approx$ 2 miles away		-0.002		0.011
		(0.002)		(0.008)
$\approx \sqrt{5}$ miles away		0.001		0.011
		(0.003)		(0.010)
constant	0.019***	0.019***	0.904***	0.892***
	(0.006)	(0.006)	(0.021)	(0.026)
R squared	0.668	0.668	0.326	0.326
p value joint significance		0.000		0.000
p value non-16/36 test		0.073		0.149
Observations	12549	12549	12548	12548

Table 3: Regressions of the fraction of a section that is in state ownership (columns 1 and 2) or in federal ownership (columns 3 and 4) as a function of whether a section is numbered 16 or 36, and proximity of the section to the closest section numbered 16 or 36. The first p value is a the joint test that all coefficients—except for the constant—are equal to zero. The second p value is the joint test that coefficients for 1 mile, $\sqrt{2}$ miles, 2 miles, and $\sqrt{5}$ miles are all equal to zero. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) mean elevation	(2) range elevation	(3) wetlands	(4) checked
is 16/36	-20.294	-0.665	-0.024***	-0.004
	(19.200)	(3.841)	(0.008)	(0.011)
$\approx$ 1 mile away	1.178	4.877	-0.015*	-0.001
	(13.490)	(3.650)	(0.008)	(0.006)
$\approx \sqrt{2}$ miles away	-3.874	1.555	-0.017**	-0.004
	(12.967)	(2.725)	(0.008)	(0.005)
$\approx$ 2 miles away	-4.799	4.052	-0.007	-0.004
	(12.984)	(3.918)	(0.006)	(0.012)
$\approx \sqrt{5}$ miles away	6.520	4.259	-0.013*	0.002
	(20.324)	(3.802)	(0.007)	(0.010)
constant	2102.140***	80.981***	0.073***	0.228***
	(24.606)	(7.487)	(0.013)	(0.059)
R squared	0.000	0.000	0.001	0.000
p value joint significance	0.095	0.108	0.000	0.489
Observations	12506	12506	12549	12549

Table 4: Comparing mean elevation, range of elevation within section, the fraction of the section with any wetlands, and the fraction of the section that was visually checked by a surveyor (rather than estimated using geospatial methods). Elevation data is not available for all sections. Most sections missing elevation data are on the southern border with Utah. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) settled	(2) muni.	(3) fence	(4) dry crop	(5) irrig.	(6) surf. mine
is 16/36	-0.001	-0.003	-0.016	-0.001	-0.007	-0.001
	(0.001)	(0.003)	(0.017)	(0.000)	(0.006)	(0.000)
$\approx$ 1 mile away	-0.001	-0.002	-0.006	-0.001	-0.004	-0.000
	(0.001)	(0.003)	(0.014)	(0.000)	(0.005)	(0.000)
$\approx \sqrt{2}$ miles away	-0.001	-0.002	-0.009	-0.000	-0.004	-0.000
	(0.001)	(0.003)	(0.016)	(0.000)	(0.005)	(0.000)
$\approx$ 2 miles away	-0.000	0.000	-0.010	-0.000	0.002	-0.000
	(0.000)	(0.002)	(0.010)	(0.001)	(0.004)	(0.000)
$\approx \sqrt{5}$ miles away	-0.001	0.000	-0.015	-0.000	-0.001	-0.000
	(0.000)	(0.002)	(0.016)	(0.001)	(0.004)	(0.000)
constant	0.001	0.004	0.317***	0.001	0.037***	0.001
	(0.001)	(0.003)	(0.047)	(0.001)	(0.014)	(0.000)
R squared	0.001	0.000	0.000	0.000	0.000	0.000
p value joint significance	0.351	0.255	0.846	0.229	0.000	0.556
Observations	12549	12549	12549	12549	12549	12549

Table 5: Regression of land coverage measures within a section. Fraction of a section with any settlement (column 1), whether there is any municipality (dry crop farming (column 2), whether there is any fencing within the section (column 3), fraction of section with dry crop (column 4), fraction of section with irrigated crops (column 5), and fraction of a section with a surface mine (column 6). Whether the outcomes in columns 1 and 4-6 were visually determined or estimated by geospatial methods is given in column 4 of table 4. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) expl.	(2) expl.	(3) expl./first	(4) expl./first
is 16/36	0.032**	0.032**	0.020	0.020
	(0.013)	(0.013)	(0.018)	(0.019)
$\approx$ 1 mile away	-0.004	-0.004	-0.026**	-0.026**
	(0.008)	(0.008)	(0.012)	(0.012)
$\approx \sqrt{2}$ miles away	-0.009	-0.009	-0.029**	-0.030**
	(0.008)	(0.008)	(0.014)	(0.013)
$\approx$ 2 miles away	-0.022**	-0.021**	-0.028**	-0.026**
	(0.009)	(0.009)	(0.012)	(0.012)
$\approx \sqrt{5}$ miles away	-0.008	-0.008	-0.025*	-0.025*
	(0.009)	(0.010)	(0.014)	(0.014)
constant	0.109***	0.045***	0.247***	0.086
	(0.011)	(0.012)	(0.045)	(0.058)
physical chars.	No	Yes	No	Yes
R squared	0.002	0.004	0.001	0.008
p value joint test	0.005	0.008	0.000	0.001
p value non-16/36	0.032	0.046	0.100	0.123
Observations	12549	12549	12549	12549

Table 6: Regressions of the probability that a section has ever had an exploratory well by 2010 (columns 1 and 2) or ever had drilling by 2010 (columns 5 and 6). The first p value is the test that the coefficients for 16/36 and 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away are all equal to zero. The second p value is the test that the coefficients for 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away all equal to zero. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) 1(prod | drill)	(2) 1(prod | drill)	(3) 1(prod well)	(4) 1(prod well)	(5) # prod wells	(6) # prod wells
is 16/36	0.072*	0.072**	0.031**	0.031**	0.248	0.236
	(0.037)	(0.036)	(0.014)	(0.014)	(0.240)	(0.240)
$\approx$ 1 mile away	0.008	0.007	-0.014	-0.014	-0.093	-0.102
	(0.048)	(0.047)	(0.015)	(0.014)	(0.089)	(0.090)
$\approx \sqrt{2}$ miles away	0.038	0.039	-0.009	-0.010	-0.032	-0.041
	(0.038)	(0.037)	(0.011)	(0.010)	(0.072)	(0.073)
$\approx$ 2 miles away	0.049	0.050	-0.006	-0.005	-0.013	-0.012
	(0.042)	(0.043)	(0.011)	(0.011)	(0.084)	(0.080)
$\approx \sqrt{5}$ miles away	0.030	0.029	-0.008	-0.009	0.069	0.063
	(0.039)	(0.039)	(0.013)	(0.012)	(0.096)	(0.095)
constant	0.606***	0.469***	0.150***	0.024	0.835**	0.490
	(0.066)	(0.157)	(0.039)	(0.053)	(0.348)	(0.394)
physical chars.	No	Yes	No	Yes	No	Yes
R squared	0.002	0.004	0.001	0.007	0.000	0.001
p value joint test	0.090	0.082	0.036	0.041	0.004	0.005
p value non-16/36	0.096	0.090	0.739	0.654	0.574	0.519
Observations	2814	2814	12549	12549	12549	12549

Table 7: Columns 1 and 2 are regressions of the probability that a section ever has a well drilled on it that is reported to be productive, conditional on any well being drilled on the section by 2010. Columns 3 and 4 are regressions of the probability that a section has ever had an well drilled by 2010 that is reported to have ever been productive. Columns 5 and 6 report the total count of wells ever drilled that have been reported to be productive. The first p value is the test that the coefficients for 16/36 and 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away are all equal to zero. The second p value is the test that the coefficients for 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away all equal to zero. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) BOE 12	(2) BOE 24	(3) BOE 36	(4) gas 12	(5) gas 24	(6) gas 36	(7) oil 12	(8) oil 24	(9) oil 36
is 16/36	-0.48	-0.48*	-0.46	-0.60*	-0.61*	-0.59*	-0.25	-0.28	-0.27
	(0.30)	(0.29)	(0.29)	(0.33)	(0.32)	(0.31)	(0.27)	(0.26)	(0.26)
$\approx$ 1 mile away	-0.25**	-0.21**	-0.19*	-0.26***	-0.25***	-0.24***	-0.14	-0.11	-0.09
	(0.11)	(0.10)	(0.11)	(0.10)	(0.08)	(0.09)	(0.13)	(0.14)	(0.15)
$\approx \sqrt{2}$ miles away	-0.18**	-0.18***	-0.17**	-0.23**	-0.24**	-0.27**	0.02	0.00	0.01
	(0.09)	(0.07)	(0.07)	(0.11)	(0.10)	(0.12)	(0.11)	(0.11)	(0.12)
$\approx$ 2 miles away	-0.30**	-0.28*	-0.25*	-0.23	-0.23	-0.22	-0.17	-0.16	-0.15
	(0.15)	(0.15)	(0.15)	(0.14)	(0.14)	(0.14)	(0.16)	(0.17)	(0.17)
$\approx \sqrt{5}$ miles away	-0.23***	-0.23***	-0.22***	-0.23**	-0.24**	-0.31*	-0.08	-0.10	-0.10
	(0.08)	(0.07)	(0.07)	(0.11)	(0.11)	(0.17)	(0.09)	(0.10)	(0.11)
constant	10.84***	11.31***	11.53***	12.54***	13.03***	13.25***	7.85***	8.27***	8.46***
	(0.52)	(0.49)	(0.47)	(0.56)	(0.52)	(0.49)	(0.52)	(0.51)	(0.49)
R squared	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Observations	7798	7798	7798	7567	7587	7619	7238	7316	7340

Table 8: Regressions of log total production for the first 12, 24, and 36 months of production. Production measured in barrel-of-oil equivalent production (columns 1-3), natural gas (columns 4-6), and oil (columns 7-9). I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) BOE	(2) BOE	(3) Gas	(4) Gas	(5) Oil	(6) Oil
is 16/36	0.05	0.05	0.10	0.10	0.05	0.04
	(0.15)	(0.15)	(0.16)	(0.16)	(0.13)	(0.12)
$\approx$ 1 mile away	-0.23*	-0.25**	-0.24	-0.26**	-0.18*	-0.19*
	(0.13)	(0.11)	(0.15)	(0.13)	(0.10)	(0.10)
$\approx \sqrt{2}$ miles away	-0.21	-0.21*	-0.21	-0.21	-0.16	-0.17
	(0.14)	(0.12)	(0.16)	(0.14)	(0.11)	(0.10)
$\approx$ 2 miles away	-0.18*	-0.19*	-0.18	-0.19	-0.12	-0.13
	(0.10)	(0.11)	(0.12)	(0.13)	(0.10)	(0.10)
$\approx \sqrt{5}$ miles away	-0.21*	-0.21**	-0.21	-0.22*	-0.13	-0.15
	(0.12)	(0.10)	(0.14)	(0.11)	(0.11)	(0.09)
constant	1.48***		1.62***		1.03***	
	(0.44)		(0.50)		(0.32)	
township FE	No	Yes	No	Yes	No	Yes
R squared	0.00	0.45	0.00	0.45	0.00	0.45
p value joint test	0.25	0.02	0.27	0.01	0.11	0.01
p value non-16/36	0.42	0.13	0.55	0.21	0.40	0.04
p value not-intercept	0.24	0.02	0.19	0.00	0.10	0.03
Observations	12549	12549	12549	12549	12549	12549

Table 9: Dependent variable is MacKinnon-Magee transform of total 1980-2010 production for wells drilled on or after 1980, aggregated to the section level. I use Conley standard errors with uniform weights and a maximum correlation distance of 20 miles.

	(1) 16/36	(2) $\approx$ 1 mile	(3) $\approx \sqrt{2}$ miles	(4) $\approx$ 2 miles	(5) $\approx \sqrt{5}$ miles	(6) intercept	(7) joint test	(8) non 16/36 test	(9) 16/36-$\sqrt{5}$ test
1930	0.002	-0.004	-0.005	-0.002	-0.003	0.018**	0.213	0.177	0.000
	(0.004)	(0.005)	(0.005)	(0.005)	(0.004)	(0.009)			
1940	0.005	-0.003	-0.005	0.001	0.000	0.018**	0.000	0.000	0.000
	(0.005)	(0.005)	(0.005)	(0.005)	(0.004)	(0.009)			
1950	0.005	-0.003	-0.006	0.001	0.001	0.023**	0.094	0.256	0.055
	(0.005)	(0.004)	(0.004)	(0.004)	(0.004)	(0.011)			
1960	-0.002	0.004	-0.006	0.001	-0.005	0.054***	0.330	0.221	0.230
	(0.008)	(0.006)	(0.008)	(0.007)	(0.007)	(0.018)			
1970	0.015	0.017	0.002	0.007	0.012*	0.078***	0.053	0.031	0.060
	(0.011)	(0.007)	(0.006)	(0.006)	(0.007)	(0.025)			
1980	0.002	0.003	-0.009	-0.006	-0.005*	0.133***	0.298	0.279	0.200
	(0.010)	(0.010)	(0.012)	(0.011)	(0.009)	(0.031)			
1990	-0.003	-0.014	-0.021**	-0.021*	-0.020*	0.181***	0.090	0.263	0.145
	(0.012)	(0.010)	(0.011)	(0.011)	(0.011)	(0.039)			
2000	-0.006	-0.024	-0.027**	-0.028**	-0.025*	0.216***	0.002	0.198	0.005
	(0.013)	(0.010)	(0.012)	(0.014)	(0.013)	(0.042)			
2010	0.020	-0.026	-0.029**	-0.028**	-0.025*	0.247***	0.001	0.181	0.009
	(0.018)	(0.012)	(0.014)	(0.012)	(0.014)	(0.045)			
	R squared:	0.064							

Table 10: Seemingly unrelated regression of whether there is any drilling in a section by date T, for T=1930 to 2010, in 10 year increments. Sample size is 12,594 for each year. I use Conley standard errors with uniform weights and a maximum correlation distance of 20 miles. Column 7 gives the p value for a joint test that the coefficients in columns 1-5 in a given year are all equal to zero. Column 8 gives the p value for a joint test that the coefficients in columns 2-5 are all equal to zero. Column 9 gives the p value for a joint test the the coefficients in columns 1-5 are all equal to each other. The test that the difference between each coefficient in 2010 versus 1960 is equal to zero is rejected with a p value of 2.6×10^{-6}.

	Any lease	Federal lease	State lease
All sections	**98.9%**	94.5%	10.1%
Not 16/36	98.8%	**98.7%**	5.6%
16/36	99.3%	23.4%	**86.2%**
16/36, has state mineral land	99.8%	10.4%	**99.6%**

Table 11: Fraction of sections that ever had a lease reported on them

	(1) BOE	(2) BOE	(3) Gas	(4) Gas	(5) Oil	(6) Oil
is 16/36	-0.04	-0.01	-0.04	-0.01	-0.02	0.00
	(0.08)	(0.09)	(0.08)	(0.08)	(0.07)	(0.08)
$\approx$ 1 mile away	0.03	0.02	0.03	0.02	0.01	0.00
	(0.05)	(0.06)	(0.05)	(0.06)	(0.05)	(0.05)
$\approx \sqrt{2}$ miles away	-0.06	-0.04	-0.04	-0.03	-0.06	-0.06
	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)
$\approx$ 2 miles away	0.02	0.01	-0.01	-0.02	0.05	0.03
	(0.04)	(0.05)	(0.04)	(0.05)	(0.04)	(0.04)
$\approx \sqrt{5}$ miles away	-0.05*	-0.05	-0.06**	-0.06	-0.04	-0.04
	(0.03)	(0.04)	(0.03)	(0.04)	(0.04)	(0.03)
intercept	-0.53***		-0.52***		-0.64***	
	(0.07)		(0.07)		(0.07)	
Field FE	No	Yes	No	Yes	No	Yes
R squared	0.00	0.11	0.00	0.12	0.00	0.08
p value joint test	0.00	0.01	0.01	0.06	0.02	0.02
Observations	7430	7430	7235	7235	6822	6822

Table 12: Percentage change in production from the first year to the second year, wells drilled after 1978. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

11 Figures

6	5	4	3	2	1	6	5	4	3	2	1	6	5	4	3	2	1
7	8	9	10	11	12	7	8	9	10	11	12	7	8	9	10	11	12
18	17	16	15	14	13	18	17	16	15	14	13	18	17	16	15	14	13
19	20	21	22	23	24	19	20	21	22	23	24	19	20	21	22	23	24
30	29	28	27	26	25	30	29	28	27	26	25	30	29	28	27	26	25
31	32	33	34	35	36	31	32	33	34	35	36	31	32	33	34	35	36
6	5	4	3	2	1	6	5	4	3	2	1	6	5	4	3	2	1
7	8	9	10	11	12	7	8	9	10	11	12	7	8	9	10	11	12
18	17	16	15	14	13	18	17	16	15	14	13	18	17	16	15	14	13
19	20	21	22	23	24	19	20	21	22	23	24	19	20	21	22	23	24
30	29	28	27	26	25	30	29	28	27	26	25	30	29	28	27	26	25
31	32	33	34	35	36	31	32	33	34	35	36	31	32	33	34	35	36

√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1
√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2
2	1	16	1	2	3	2	1	16	1	2	3	2	1	16	1	2	3
√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2
√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1
1	2	3	2	1	36	1	2	3	2	1	36	1	2	3	2	1	36
√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1
√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2
2	1	16	1	2	3	2	1	16	1	2	3	2	1	16	1	2	3
√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2
√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1	√2	√5	2	√5	√2	1
1	2	3	2	1	36	1	2	3	2	1	36	1	2	3	2	1	36

Figure 1: Two diagrams showing original section numbering and how to construct the distance to the closest 16 or 36 section, as used in equation 8.

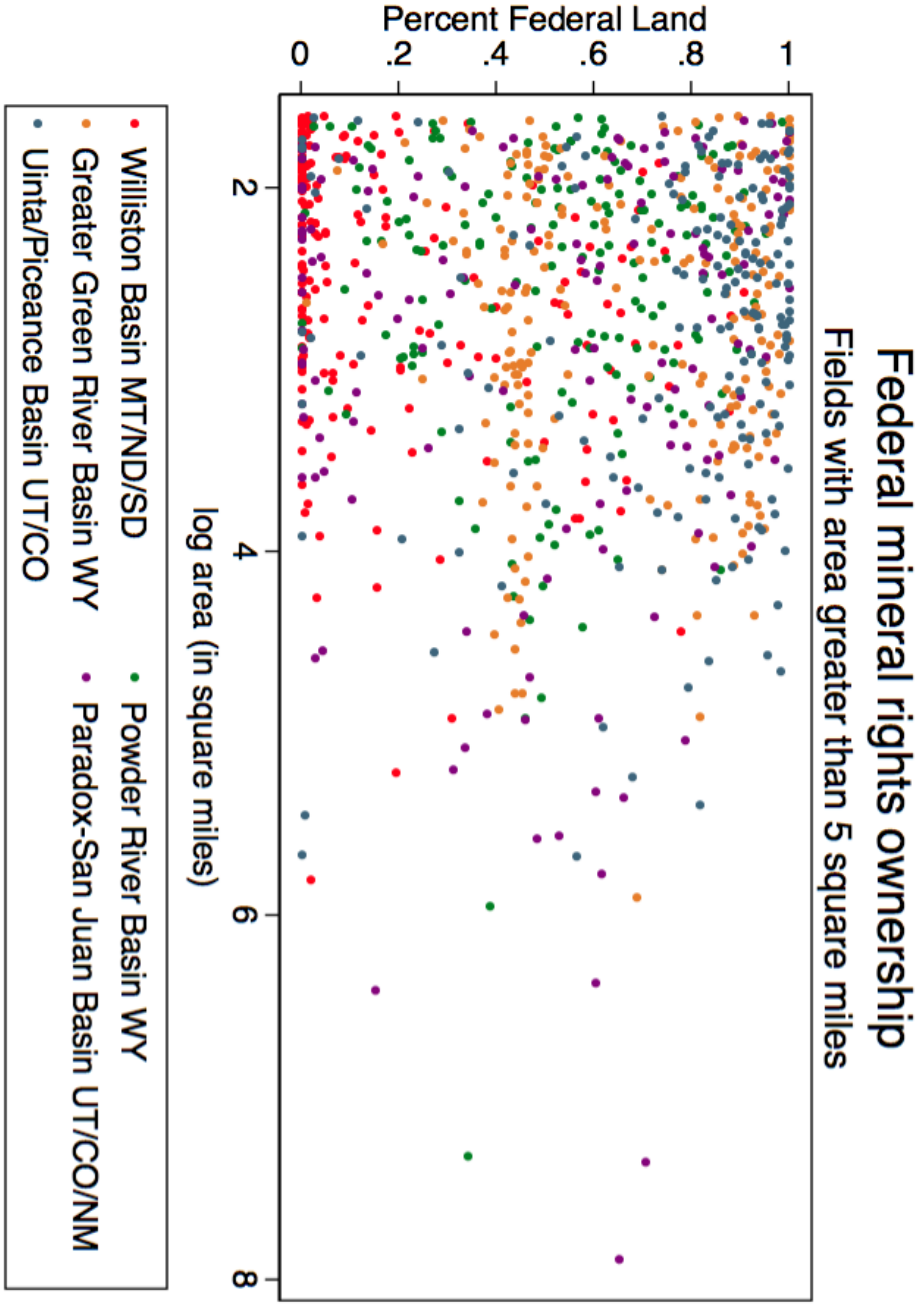

Figure 2: Fraction of fields that are federally owned, for a sample of basins in the Western United States.

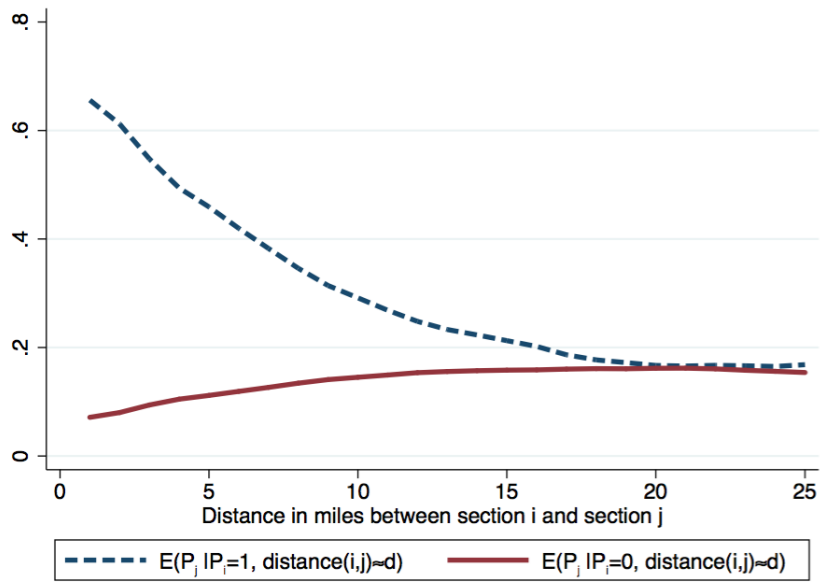

Figure 3: A graph showing the extent to which whether a section ever had a productive well predicts whether another section d miles away also has a productive well. Here P_i is indicator variables that indicates whether section i had a productive well, and d is the distance in miles between two sections i and j.

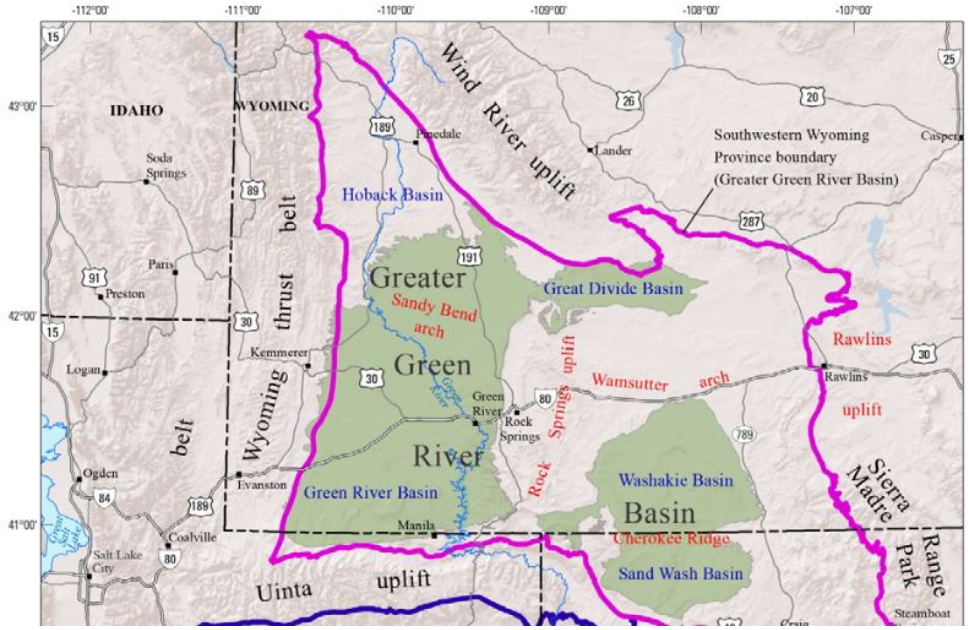

Figure 4: Map of the Greater Green River basin. The Greater Green River Basin is marked with a pink line. Source: `http://theenergyharbinger.files.wordpress.com/2013/04/usgs_green-river-basin.jpg`

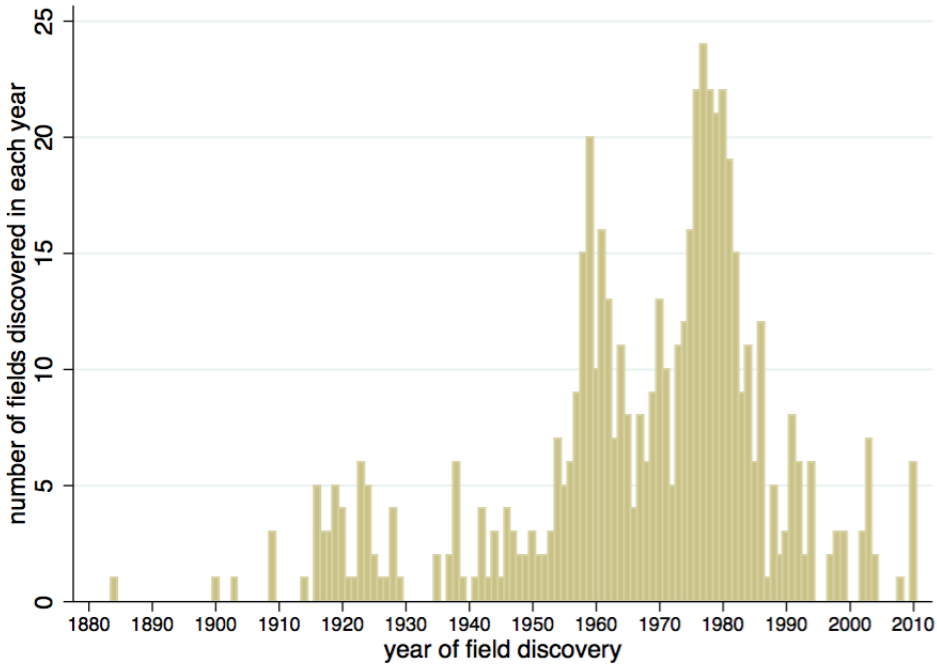

Figure 5: Year of field discovery for fields in Sweetwater, Sublette, Carbon, Lincoln, Uinta, Fremont, and Teton counties, which are the counties that contain the Greater Green River basin. Compiled from 2011 field master code lists. Available online at `http://www.eia.gov/naturalgas/fieldcode/`.

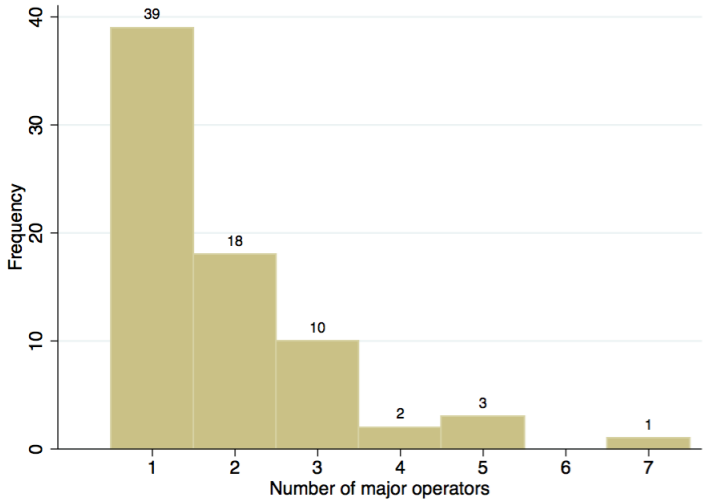

Figure 6: Number of major operators in 71 fields in the Greater Green River Basin. Excludes reservoirs that lie predominately under the transcontinental railroad checkerboard region.

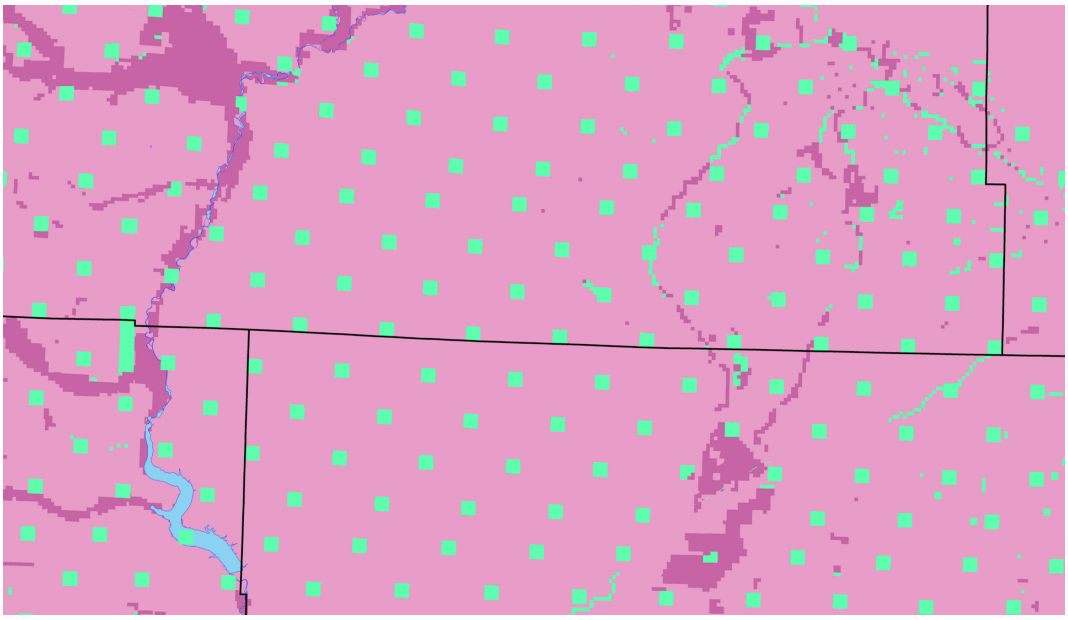

Figure 7: Current mineral ownership in a subset of the Greater Green River basin. Dark pink denotes private ownership, light pink denotes federal ownership, and light green denotes state ownership. The dark lines are county lines.

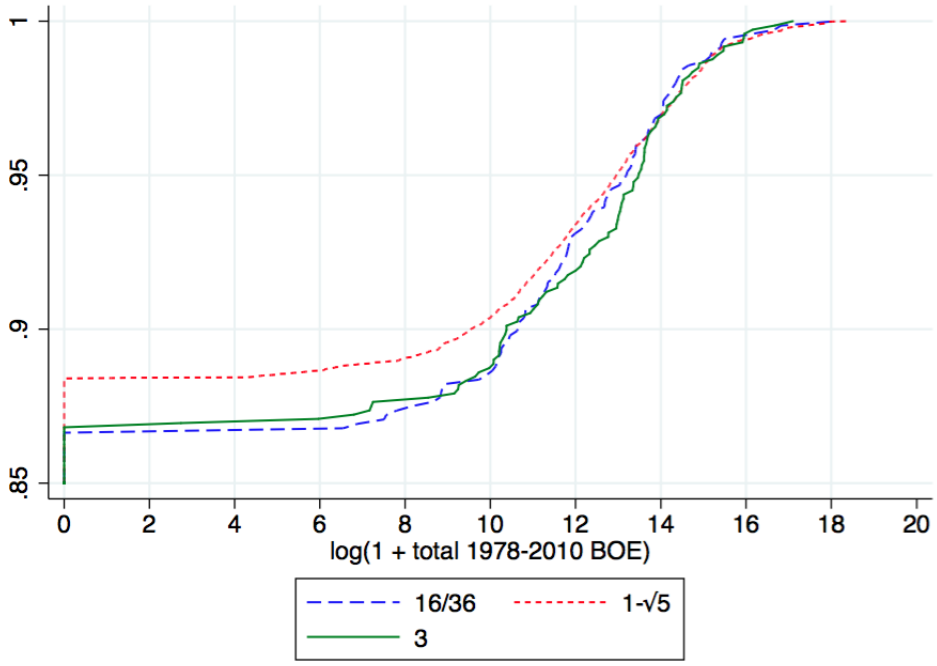

Figure 8: CDF of total section-level 1978-2010 BOE production, comparing 16/36, sections 1-$\sqrt{5}$ miles away, and sections 3 miles away. I do not graph the values of the cdf below 0.85.

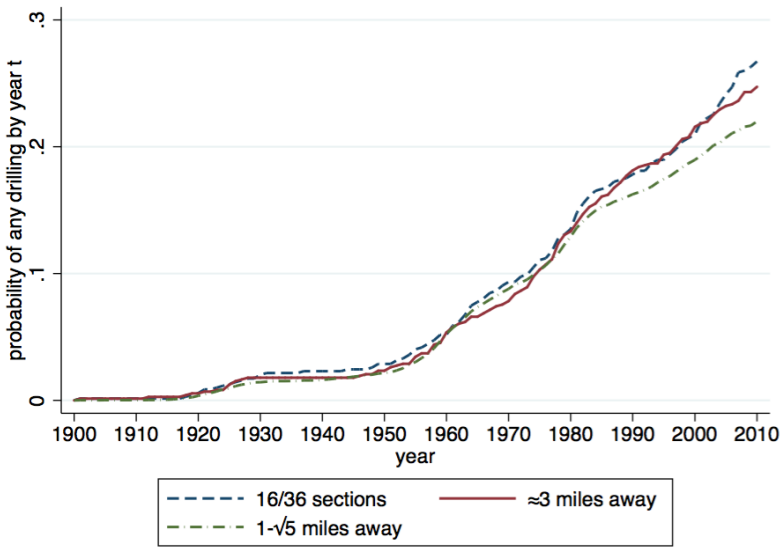

Figure 9: Rollout of drilling on 16/36 sections, sections ≈3 miles away, and sections that are between 1 and $\sqrt{5}$ miles away. The vertical axis measures the fraction of sections in each category that have been drilled by that date

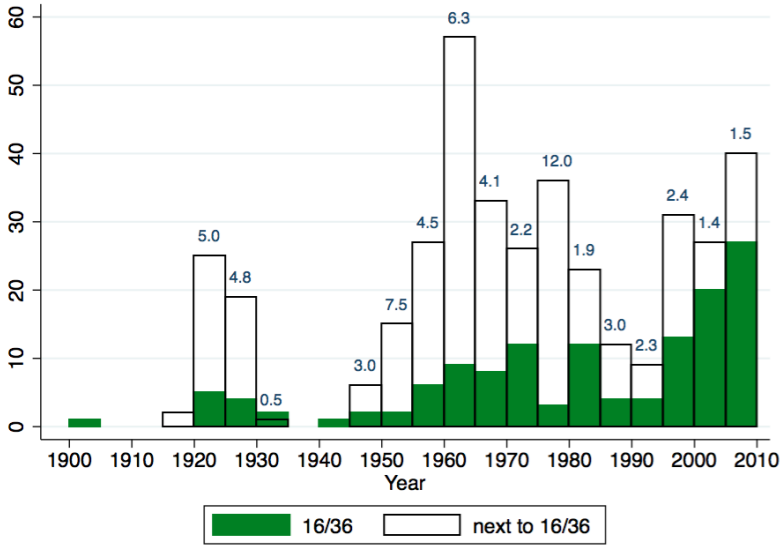

Figure 10: Number of wildcat wells drilled on sections numbered 16 or 36 and wells drilled on sections that are adjacent to sections numbered 16 or 36, arranged by year.

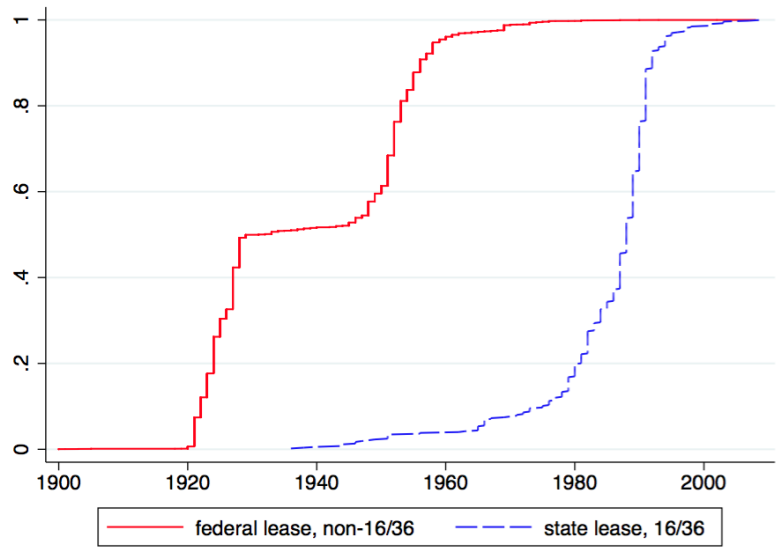

Figure 11: Rollout of federal leasing on non-16/36 sections (conditional on a federal lease ever being issued), as well as of state leasing on 16/36 sections (conditional on a state lease ever being issued).

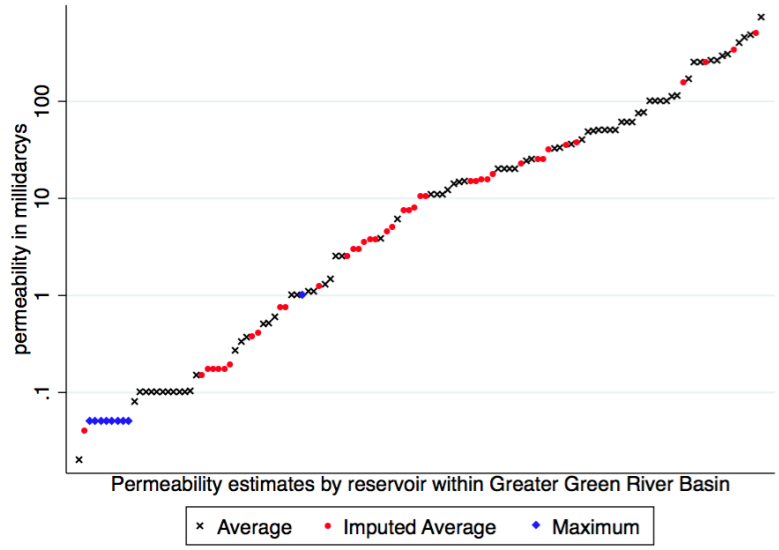

Figure 12: Geological estimates of permeability in reservoirs within fields in the Greater Green River Basin. Excludes reservoirs that lie predominately under the transcontinental railroad checkerboard region. This plots the average permeability if reported. If a maximum and minimum permeability is reported but not an average, this charts the mean of the maximum and minimum. In some cases only a maximum permeability is reported

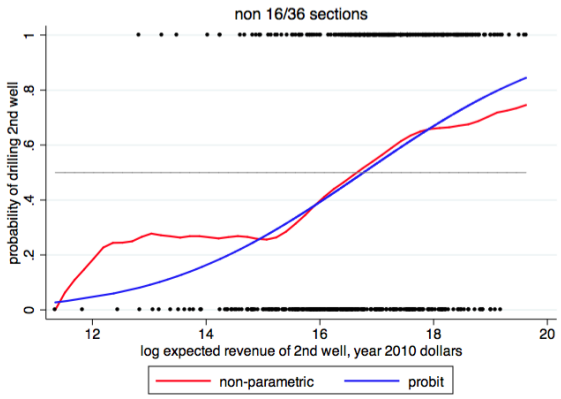

Figure 13: Estimates of the cdf of costs on non-16/36 sections. Probit and non-parametric regressions of whether a second well was drilled as a function of expected revenue on the second well.

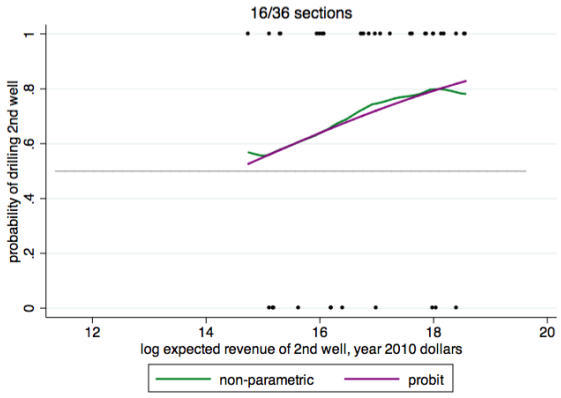

Figure 14: Estimates of the cdf of costs on non-16/36 sections. Probit and non-parametric regressions of whether a second well was drilled as a function of expected revenue on the second well.

12 Appendix

In this appendix, I first present proofs of the propositions. Then I discuss some robustness results related to well-level production. Third, I discuss details of the cost estimation. Fourth, I discuss a simple case of the two plot model where regulation on federal land has no effect on the predicted number of wells drilled.

12.1 Proofs of the propositions in section 3.

I provide proofs of the propositions in section 3. For simplicity, I assume that if the firm drills an exploratory well, it always drills it on plot 1. This holds without loss of generality: In the state-federal case where $C_1 = C_S$ and $C_2 = C_F$, the firm strictly prefers to drill plot 1 first. In the federal-federal case where $C_1 = C_2 = C_F$, the firm is indifferent and so I assume the firm drills plot 1 first. Note that expected outcomes for a federal plot (or a federal well) will be an average of plot (or well) outcomes on both 1 and 2.

Throughout, I use the notation $F_{12}(R_1, R_2|\mu)$ for the joint cdf of R_1 and R_2, $F_1(R_1|\mu)$ to denote the marginal cdf of R_1, and $F_2(R_2|R_1, \mu)$ to denote the conditional cdf of R_2.

Propositions:

1. If $C_1 < C_2$ then $\pi_1 > \pi_2$.

   Proof. Define $X_1 = E(R_2|R_1)$ and $X_2 = E(R_1|R_2)$. Because of symmetry of beliefs, the distribution of X_1 is identical to the distribution of X_2. Therefore we can focus on $X = E(R_i|R_j)$. Re-writing the definition of π_1 by incorporating the first period cost into the integral and by using indicator functions, we have:

$$
\begin{aligned}
\pi_1 &= \mu + \int_X -C_1 + 1(X - C_2 \geq 0)(X - C_2)\partial F(X) \\
&= \mu + \int_X -C_1 + [1(X - C_1 \geq 0) - 1(C_1 \leq X < C_2)](X - C_1 + C_1 - C_2)\partial F(X) \\
&= \pi_2 + \int_X C_2 - C_1 + 1(X - C_1)(C_1 - C_2) - 1(C_1 \leq X < C_2)(X - C_2)\partial F(X) \\
&= \pi_2 + \int_X 1(X - C_1 < 0)(C_2 - C_1) - 1(C_1 \leq X < C_2)(X - C_2)\partial F(X) \\
&> \pi_2
\end{aligned}
$$

   □

2. If $C_1 = C_2$ then $\pi_1 = \pi_2$.

   Proof. If $C_1 = C_2$, then π_1 and π_2 are identical because symmetry of beliefs implies that $E(R_2|R_1 = r) = E(R_1|R_2 = r)$ for all values of r. □

3. There exists an $R_1^*(\mu, C_2)$ such that drilling only happens on plot 2 if $R_1 \geq R_1^*$.

   Proof. Expected profits on plot 2 are $E(R_2|R_1, \mu) - C_2$. Recall from the assumptions that $\partial F_2(R_2|R_1, \mu)/\partial R_1$ is strictly decreasing in R_1. This implies that $E(R_2|R_1)$ is strictly increasing in R_1. Therefore there is a value $R_1^*(\mu, C_2)$ such that $E(R_2|R_1 = R_1^*) - C_2 = 0$, and $E(R_2|R_1 = R_1^*) - C_2 > 0$ for all values of $R_1 > R_1^*$. □

4. R_1^* is increasing in C_2.

   Proof. Total differentiation of the identity $E(R_2|R_1^*(C_2, \mu), \mu) = C_2$ yields:

$$\frac{\partial R_1^*}{\partial C_2} = \left[\frac{\partial E(R_2|R_1)}{\partial R_1}\right]^{-1} > 0$$

   □

5. R_1^* is decreasing in μ.

   Proof. As R_1^* is the reserves on plot 1 that make the firm indifferent between drilling plot 2 and not drilling, it satisfies the following equation:

$$\int_0^\infty R_2 f(R_2|R_1 = R_1^*(\mu, C_2), \mu)\partial R_2 = C_2 \tag{9}$$

   This can be re-written as:

$$\int_0^\infty (1 - F(R_2|R_1 = R_1^*(\mu, C_2), \mu))\partial R_2 = C_2 \tag{10}$$

   (Note: The expected value of R_2 can be written as the integral of $1-F(R_2|R_1, \mu)$ because the bounds of integration are from zero to infinity. This holds even if there is a mass point of R_2 at zero.)

   Taking derivatives with respect to μ and re-arranging gives:

$$\frac{\partial R_1^*}{\partial \mu} = \frac{-1 + \int_0^\infty -\dfrac{\partial F(R_2|R_1, \mu)}{\partial \mu}\partial R_2}{\int_0^\infty -\dfrac{\partial F(R_2|R_1, \mu)}{\partial R_1}\partial R_2} \tag{11}$$

   Because $F(R_2|R_1, \mu)$ is decreasing in both R_1 and μ, this implies that $\dfrac{\partial R_1^*}{\partial \mu}$ is negative. □

6. There exists a μ^* such that the firm only drills on plot 1 if $\mu \geq \mu^*$.

Proof. Recall that:

$$\pi_1(\mu) = \mu - C_1 + E[\max\{E(R_2|R_1, \mu) - C_2, 0\}]$$

From the assumptions, $F(R_2|R_1, \mu)$ is strictly decreasing in μ, which means that $E(R_2|R_1, \mu)$ is strictly increasing in μ. This implies both $E[\max\{E(R_2|R_1, \mu) - C_2, 0\}]$ is weakly increasing in μ, and π_1 is strictly increasing in μ. Therefore there is a minimum $\mu^*(C_1, C_2)$ such that $\pi_1 = 0$ and for all values of $\mu > \mu^*$, $\pi_1 > 0$. □

7. μ^* is increasing in both C_1 and C_2:

   Proof. The threshold $\mu^*(C_1, C_2)$ satisfies the equation

$$\pi_1(\mu^*(C_1, C_2), C_1, C_2) = 0 \tag{12}$$

   Differentiating with respect to C_i, for $i \in \{1, 2\}$, and re-arranging:

$$\frac{\partial \mu^*}{\partial C_i} = -\frac{\frac{\partial \pi_1}{\partial C_i}}{\frac{\partial \pi_1}{\partial \mu}} \tag{13}$$

   Because π_1 is increasing in μ and decreasing in C_1 and C_2, μ^* is increasing in C_1 and C_2. □

8. The probability that a particular plot of land has an exploratory well is highest on state land, lowest on federal land next to state land, and medium for federal land that is far from state land.

   Proof. The probability of an exploratory well on state land (in the state-federal case) is:

$$1 - G(\mu^*(C_S, C_F) \tag{14}$$

   while the probability that the exploratory well on adjacent federal land is zero.

   The probability of an exploratory well on federal land in the federal-federal case is:

$$0.5 \cdot (1 - G(\mu^*(C_F, C_F)) \tag{15}$$

   This is less than the probability of exploratory drilling on state land—both because of the 0.5, as well as because $\mu^*(C_S, C_F) < \mu^*(C_F, C_F)$. □

9. The probability of ever drilling is highest on state land and lower on federal land. However it is ambiguous whether federal land close to or far from state land will have higher rates of ever drilling.

Proof. The probability of ever drilling on state land is

$$1 - G(\mu^*(C_S, C_F) \tag{16}$$

The probability of ever drilling on adjacent federal land (in the state-federal case) is:

$$\int_{\mu^*(C_S,C_F)}^{\infty} F_1(R_E^*|\mu)\partial G(\mu) \tag{17}$$

The probability of ever drilling on federal land in the federal-federal case is:

$$0.5 \cdot (1 - G(\mu^*(C_F, C_F)) + 0.5 \cdot \int_{\mu^*(C_F,C_F)}^{\infty} F_1(R|\mu)\partial G(\mu) \tag{18}$$

The expression in 16 is greater than that in 18 because $F_1(R_E^*|\mu) \leq 1$. The expression in 16 is greater than that in 18 both because $\mu^*(C_S, C_F) < \mu^*(C_F, C_F)$ and because conditional on $\mu \geq \mu^*(C_F, C_F)$, there is less than a 100% probability that the plot will ever be drilled.

□

10. If $0 \leq a(\mu) \leq \min\{b(\mu), c(\mu)\} \leq \max\{b(\mu), c(\mu)\} < 1$, $a(\mu) < b(\mu)c(\mu)$, $b'(\mu) \geq 0$, and $c'(\mu) \leq 0$, then:

$$\frac{\int_x^y a(\mu)\partial G(\mu)}{\int_x^y b(\mu)\partial G(\mu)} < \frac{\int_x^y c(\mu)\partial G(\mu)}{\int_x^y \partial G(\mu)} \tag{19}$$

Proof. Because $a(\mu) < b(\mu)c(\mu)$, we have:

$$\int_x^y a(\mu)\partial G(\mu) < \int_x^y b(\mu)c(\mu)\partial G(\mu) \tag{20}$$

$$\leq \left[\int_x^y b(\mu)\partial G(\mu)\right]\left[\int_x^y c(\mu)\partial G(\mu)\right] \tag{21}$$

$$\leq \frac{\left[\int_x^y b(\mu)\partial G(\mu)\right]\left[\int_x^y c(\mu)\partial G(\mu)\right]}{\int_x^y \partial G(\mu)} \tag{22}$$

where the first inequality follows by definition. The second inequality follows because $b(\mu)$ is increasing in μ while $c(\mu)$ is decreasing. As the two are negatively correlated, the expectation of the product is less than the product of the expectations (see Tao and Vu (2006), page 20 for a formal proof). Finally, the last line follows follows because $G(\mu)$ is a cdf—increasing in μ and bounded above by one and below by zero.

Note: This proof also holds if $b'(\mu) \leq 0$, and $c'(\mu) \geq 0$ □

11. The first well drilled will have on average lower production than the second well

Proof. The cdf of production for the first well drilled is:

$$P(R_1 < r) = \frac{\int_{\mu^*}^{\infty} F_1(r|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} F_1(R|\mu)\partial G(\mu)} \tag{23}$$

while the cdf for production for the second well drilled is:

$$P(R_2 < r) = \frac{\int_{\mu^*}^{\infty} \int_{R_E^*}^{\infty} F_2(r|R_1,\mu)\partial F_1(R|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} \int_{R_E^*}^{\infty} \partial F_1(R|\mu)\partial G(\mu)} \tag{24}$$

Here, we can use proposition 10 from above, where:

$$a(\mu) = \int_{R_E^*}^{\infty} F_2(r|R_1,\mu)\partial F_1(R|\mu) \tag{25}$$

$$b(\mu) = \int_{R_E^*}^{\infty} \partial F_1(R|\mu) = 1 - F_1(R_E^*|\mu) \tag{26}$$

$$c(\mu) = F_1(r|\mu) \tag{27}$$

and the limits of integration are $x = \mu^*$ and $y = \infty$

Because the first well will have a higher probability that $R < r$, for any r, this means that expected production for an exploratory well will be lower than expected production for a second well. □

12. An exploratory well on state land will have lower production than an exploratory well on federal land.

    Proof. Here it is convenient to consider the log of the cdf of production on an exploratory well:

$$\log[P(R_1 < r)] = \log\left[\int_{\mu^*}^{\infty} F_1(r|\mu)\partial G(\mu)\right] - \log\left[\int_{\mu^*}^{\infty} F_1(R|\mu)\partial G(\mu)\right] \tag{28}$$

    Taking derivatives with respect to μ^* yields:

$$\frac{\partial p(R_1 < r)}{\partial \mu^*} = g(\mu^*)\frac{\int_{\mu^*}^{\infty}[F(r|\mu) - F(r|\mu^*)]\partial G(\mu)}{\left[\int_{\mu^*}^{\infty} F(r|\mu)\partial G(\mu)\right]\left[\int_{\mu^*}^{\infty} \partial G(\mu)\right]} \tag{29}$$

    Because $\mu > \mu^*$ implies $F(r|\mu) < F(r|\mu^*)$, the derivative is negative. If the minimum threshold for drilling is lower, the types of wells that will be drilled will have lower expected value. □

13. Expected production will be lowest for state wells and higher for federal wells. It is ambiguous whether federal wells that are close to state land will have higher

or lower expected production relative to federal wells that are far from state land.

Proof. This stems from the previous two propositions. Expected production on state wells will be lower than nearby federal wells because they tend to be drilled first. Expected production will be lower on state wells relative to federal wells that are far from state land (federal-federal case) both because federal-federal wells have a higher μ^*, and federal wells are also less likely to be the exploratory wells. □

12.2 Well-level production

In Table 8 I found that average well productivity is lowest on state land, next lowest on federal land next to state land, and highest on federal land far from state land. In this appendix subsection I discuss robustness checks:

In Table A1 I control for field fixed effects and date of drilling fixed effects and find very similar estimates: Column 1 shows that wells on 16/36 sections have only 63% of the BOE productivity of wells on sections 3 miles away, and wells on sections 1 mile away have 79% the productivity of wells on sections 3 miles away. Results are similar regardless of whether measuring BOE or natural gas, as well as whether using 12, 24, or 36 months of production. However oil does not show significant differences (columns 7-9), perhaps because a well produces oil or natural gas liquids tends to be much more valuable than a well that only produces natural gas such that federal costs are not high enough to prevent the development of these more lucrative wells.

As oil and gas production tends to have a long right tail, we may be concerned that production results are driven by outliers. For example, in my production data I find that the ratio of the 95th to 5th percentile of first-36 BOE production is 158. To check whether outliers are driving well productivity results, I run the same regression but excludes wells with production above the 95th percentile or below the 5th percentile (Table A2). I also control for field and date of drilling fixed effects. I find very similar estimates: Producing wells on 16/36 sections have 64% the productivity of producing wells 3 miles away, and producing wells on sections 1 mile from 16/36 sections have 81% the productivity of producing wells 3 miles away.

12.3 Cost estimation

I discuss the details of my back-of-the-envelope cost estimation. I select square mile sections where there was at least one producing well drilled on the section, and the first producing well was drilled in between 1978 and 2005. 1978 is the lower bound, both because it is the first year at which I observe well level production data and because it is approximately the time when firms began to exhibit more substitution in drilling patterns (see Figure 9). 2005 is the upper bound rather than later because including years that are too close to the present will lead me to assume that some plots would not have a second well, while in reality those second wells will shortly be drilled. This leads to a sample of 38 16/36 sections and 574 non-16/36 sections.

With the exception of wells that ended production by 2013, I do not observe total well production. Therefore I use a proxy–the first 3 years of well production, denoted $\tilde{R}_1$ and $\tilde{R}_2$ for the first and second well respectively. Under exponential decline, the first three years of production will be proportional to total production.

To calculate predicted three year production on the second well as a function of three year production on the first well, I regress second well gas production on first well gas (G) production for sections that had two wells, and second well oil production on first well oil (O) production for sections that had two wells:

$$\log \tilde{R}_{i2}^G = \beta_0^G + \beta_1^G \log \tilde{R}_{i1}^G + \epsilon_i^G$$

$$\log \tilde{R}_{i2}^O = \beta_0^O + \beta_1^O \log \tilde{R}_{i1}^O + \epsilon_i^O$$

I do these estimates separately for 16/36 sections and non-16/36 sections. From predicted log 3 year production, I first compute an estimated predicted three year production by computing:

$$E(\tilde{R}_{i2}^G) = \exp(\hat{\beta}_0^G + \hat{\beta}_1^G \log \tilde{R}_{i1}^G) \cdot E(\exp(\hat{\epsilon_i}^G))$$

$$E(\tilde{R}_{i2}^O) = \exp(\hat{\beta}_0^O + \hat{\beta}_1^O \log \tilde{R}_{i1}^O) \cdot E(\exp(\hat{\epsilon_i}^O))$$

The results of these regressions is available upon request and will be included in future versions of this paper.

I adjust these measures to compute total predicted production by using an estimated annual decline curve of 0.54 (see Table 12). I also adjust this estimate down by incorporating an estimate of the probability that a second well is dry. This gives predicted total well level oil and gas production.

To compute the value of production, I use price estimates. Crude oil prices are taken from Wyoming EIA first user crude oil price estimates. Natural gas prices are taken from EIA estimates of wellhead price. I multiple prices by total well production using only the price in the year drilled, abstracting away from issues about future expected prices. To compute prices for second wells that were not drilled, a particular challenge is not knowing what year the second well will be drilled. I assume that the second well would have been drilled in the year following the year the first well was drilled. I aggregate these measures for oil and gas to get a measure of total pre-tax revenue.

Next I subtract off taxes and royalties. I use a federal corporate income tax rate of 35%, a severance tax rate of 6%, and a county level tax of 6.2%. (County tax rates vary somewhat, but not by much; the average rate is 6.2%). I also use an estimated royalty rate of 12.5% (for federal land) for non-16/36 sections, and 15% (for state land) for 16/36 sections. This gives a measure of post-tax expected revenue.

Finally, I regress an indicator for whether a second well was drilled on log expected revenue. I do this estimate separately for 16/36 and non-16/36 sections.

$$\text{prob(2nd well drilled} = \Phi(\alpha_0 + \alpha_1 \log \text{Expected Revenue})$$

Under the probit specification, the median cost is equal to $\exp(-\hat{\alpha_0}/\hat{\alpha_1})$. To

obtain asymmetric bootstrapped confidence intervals, I do 10,000 bootstrapped estimates of the probit specification.

12.4 Incomplete Regulation and Leakage Example

Suppose that reserves on each plot 1 and 2 can be either 1 (with probability p) or 0 (with probability $1-p$). The cost of drilling a well is C and the federal government on plot 2 imposes an additional tax T to drill. Assume that if the firm knows that there are high reserves, it is worthwhile to drill ($1 > C + T$). If there is no tax, then the firm is indifferent which plot it drills on first, and it will have expected profits:

$$p - C + p(1 - C) \tag{30}$$

If there is a tax, the firm places the initial exploratory well on non-federal land and gets expected profits

$$p - C + p(1 - C - T) \tag{31}$$

As long as equation 31 is positive, then equation 30 is also positive. Then the expected number of wells drilled in the region in both cases will be $1 + p$. (Note that if p is small, then we could have cases where equation 31 is negative but equation 30 is positive, such that incomplete regulation reduces the expected number of wells.)

	(1) BOE 12	(2) BOE 24	(3) BOE 36	(4) gas 12	(5) gas 24	(6) gas 36	(7) oil 12	(8) oil 24	(9) oil 36
is 16/36	-0.46***	-0.44***	-0.44***	-0.57***	-0.56***	-0.54**	-0.10	-0.09	-0.08
	(0.12)	(0.16)	(0.16)	(0.17)	(0.20)	(0.22)	(0.14)	(0.13)	(0.13)
$\approx$ 1 mile away	-0.23***	-0.18*	-0.18*	-0.25***	-0.23**	-0.22**	-0.03	0.01	0.01
	(0.08)	(0.11)	(0.11)	(0.07)	(0.09)	(0.10)	(0.05)	(0.08)	(0.09)
$\approx \sqrt{2}$ miles away	-0.24***	-0.23**	-0.23**	-0.27***	-0.27***	-0.26**	-0.02	-0.02	-0.02
	(0.09)	(0.10)	(0.10)	(0.08)	(0.10)	(0.11)	(0.08)	(0.08)	(0.07)
$\approx$ 2 miles away	-0.18**	-0.15	-0.15	-0.14**	-0.13*	-0.12	-0.08	-0.07	-0.06
	(0.07)	(0.10)	(0.10)	(0.06)	(0.08)	(0.09)	(0.06)	(0.07)	(0.08)
$\approx \sqrt{5}$ miles away	-0.22***	-0.21**	-0.21**	-0.21***	-0.22***	-0.23**	-0.02	-0.02	-0.03
	(0.08)	(0.09)	(0.09)	(0.07)	(0.08)	(0.09)	(0.07)	(0.08)	(0.08)
R squared	0.48	0.46	0.46	0.51	0.49	0.47	0.48	0.48	0.47
Observations	7798	7798	7798	7567	7587	7619	7238	7316	7340

Table A1: Regressions of log total production for the first 12, 24, and 36 months of production. Results include field level fixed effects. Production measured in barrel-of-oil equivalent production (columns 1-3), natural gas (columns 4-6), and oil (columns 7-9). I use Conley standard errors with a Bartlett weight and maximum correlation distance of 20 miles.

	(1) BOE 12	(2) BOE 24	(3) BOE 36	(4) gas 12	(5) gas 24	(6) gas 36	(7) oil 12	(8) oil 24	(9) oil 36
is 16/36	-0.44***	-0.43***	-0.42***	-0.56***	-0.56***	-0.55***	-0.09	-0.08	-0.06
	(0.10)	(0.12)	(0.13)	(0.13)	(0.15)	(0.16)	(0.15)	(0.15)	(0.14)
$\approx$ 1 mile away	-0.21**	-0.17*	-0.16	-0.26***	-0.24**	-0.23**	0.00	0.03	0.03
	(0.09)	(0.10)	(0.11)	(0.08)	(0.10)	(0.10)	(0.09)	(0.10)	(0.10)
$\approx \sqrt{2}$ miles away	-0.23**	-0.23**	-0.23**	-0.27***	-0.28***	-0.28**	0.01	0.00	0.00
	(0.09)	(0.10)	(0.11)	(0.09)	(0.11)	(0.11)	(0.10)	(0.09)	(0.09)
$\approx$ 2 miles away	-0.15*	-0.14	-0.13	-0.14**	-0.14*	-0.13	-0.06	-0.05	-0.05
	(0.08)	(0.10)	(0.10)	(0.07)	(0.08)	(0.08)	(0.07)	(0.08)	(0.08)
$\approx \sqrt{5}$ miles away	-0.20***	-0.20**	-0.20**	-0.21***	-0.23***	-0.24***	0.01	0.00	-0.01
	(0.08)	(0.08)	(0.09)	(0.07)	(0.08)	(0.09)	(0.09)	(0.08)	(0.08)
R squared	0.50	0.48	0.46	0.53	0.51	0.51	0.50	0.50	0.50
Observations	7797	7797	7797	7567	7587	7619	7237	7315	7339

Table A2: Regressions of log total production for the first 12, 24, and 36 months of production. Production measured in barrel-of-oil equivalent production (columns 1-3), natural gas (columns 4-6), and oil (columns 7-9). Excludes observations where production is above the 95th percentile or below the 5th percentile. Includes field and date of drilling fixed effects. I use Conley standard errors with a Bartlett weight and maximum correlation distance of 20 miles.