Highlights

Investment under Government Ownership: Evidence from Oil and Gas Drilling on the Wyoming Checkerboard

Eric C. Edwards, Trevor O'Grady

- Federal land ownership leads to substantially less investment in oil and gas production in the U.S. starting in the 1990s.
- The estimated additional cost of operating on federal land implied by our results is equivalent to 14 percent of expected drilling costs.
- A novel measure of federal permitting delay shows a dramatic increase in delayed drilling on federal land at the same time drilling investments diverge across ownership type.
- Analysis at the administrative region level shows federal permitting delay from backlogged bureaucracies explains the investment divergence even when regulations remain unchanged.
- Bureaucratic process, an often overlooked feature of regulation, can materially and permanently affect real investment decisions, suggesting opportunities for welfare-enhancing policy reform.

Investment under Government Ownership: Evidence from Oil and Gas Drilling on the Wyoming Checkerboard[⋆]

Eric C. Edwards[a,1], Trevor O'Grady[b,*,2]

[a]Department of Agricultural and Resource Economics, University of California Davis, One Shields Avenue, Davis, 95616, CA, USA
[b]Department of Economics, The College of New Jersey, 2000 Pennington Rd., Ewing, 08628, NJ, USA

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ABSTRACT

We study how government ownership affects investment in oil and gas production using a natural experiment created by the Wyoming railroad checkerboard, where federally and privately owned parcels alternate at the square-mile level. Despite near-identical geology, federal land sees substantially less drilling over time. We estimate that federal ownership imposes an implicit cost on operators equivalent to 14 percent of drilling costs per well, providing a benchmark with which to evaluate environmental benefits arising from federal ownership. We find that increased permitting delays are the primary driver of our results, highlighting the economic importance of process costs in public bureaucracies.

1. Introduction

Government ownership of natural resources is widespread and has important consequences for investment decisions in extractive industries. Unlike private owners who respond primarily to profit incentives, public bureaucracies often operate under multiple mandates, balancing industry profitability with environmental protection, safety, and public accountability, and rely on formal procedures, layered review, and standardized controls to address principal–agent concerns (McCubbins, Noll, and Weingast, 1987, 1989; Shleifer, 1998; Banerjee, 1997; Prendergast, 2003). These competing goals create distinct institutional structures and contracting environments that can raise transaction costs and delay investment relative to private contracting. At the same time, they can provide public benefits—such as reduced externalities, better resource management, and broader oversight—that private markets tend to undersupply. In some contexts, centralized contracting and property institutions can also generate private benefits, for example by mitigating bargaining frictions (Covert and Sweeney, 2023) or reducing information costs (Libecap and Lueck, 2011). This paper evaluates the investment side of this tradeoff by estimating the impact of federal land ownership on private investment in oil and natural gas production in the United States and the mechanisms underlying this effect.

We exploit a natural experiment in southern Wyoming where the Pacific Railroad Acts (1862–1871) created a checkerboard pattern of land ownership, alternating square-mile parcels between the federal government and private railroad companies. This historical allocation—which included both surface and subsurface mineral rights—remains largely intact today in southern Wyoming, offering a rare setting in which land ownership is plausibly exogenous to resource potential. We use this setting to isolate the causal effect of federal ownership on investment decisions in oil and gas drilling.

We find that federal ownership deters drilling investment, with the effect emerging in the 1990s and intensifying after 2000, as delays in federal permitting processes required under the National Environmental Policy Act (NEPA) increased substantially. Compared with geologically similar private parcels, federal land had approximately twenty percent fewer wells drilled by 2015 and projects that proceeded to drilling

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*Corresponding author
ecedwar@ucdavis.edu (E.C. Edwards); ogrady@tcnj.edu (T. O'Grady)
https://are.ucdavis.edu/people/faculty/eric-edwards/ (E.C. Edwards); https://business.tcnj.edu/business-faculty/trevor-ogrady/ (T. O'Grady)
ORCID(s): 0000-0002-3588-9626 (T. O'Grady)

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in the 2000s experienced a median additional delay of six months. Using drilling data from a boom period in the early 2000s, we estimate that operators required an additional $476,000 in expected return to drill a well on federal land (after taxes and royalties, base year 2015), which is observationally equivalent to a 14 percent increase in the expected drilling cost per well (after tax deductions).

Using data at the regional level, we show that the timing of the federal-private divergences in drilling is best explained by a dramatic increase in the length and variation of delays in the federal permitting process. These delays arise following revisions of regionally-specific resource management plans (RMPs) beginning in the 1990s. While we find evidence consistent with changes in RMP rules directly affecting drilling, the preponderance of evidence indicates that the associated increases in permitting delay are the greater deterrent. Importantly, the delay in permitting does not appear to be related to site-specific environmental concerns, but rather to an overwhelmed bureaucracy that oversees a more complex regulatory process. In this respect, our results highlight the substantial, though often overlooked, role that procedural complexity and administrative capacity constraints play in the economic efficiency of federal policies.

While our results imply that federal ownership imposes a net cost on oil and gas operators, particularly after 2000, this is not necessarily true for society as a whole. Federal land management provides additional environmental safeguards intended to reduce air and water pollution, surface degradation, and ecological harm, especially in ecologically sensitive or high-risk drilling zones. Federal agencies also implement best management practices for well siting, wastewater handling, and land restoration, potentially reducing the likelihood of costly externalities borne by local communities or ecosystems.

A piecemeal analysis of these benefits indicates that federal ownership is associated with reduced drilling in ecologically sensitive areas and lower spill rates over the sample period. However, the limits of our empirical design and data availability preclude a full benefit-cost analysis. Thus, our cost estimates are best used by policy-makers as a benchmark for the required benefits that federal policies must deliver to justify observed investment deterrence. Furthermore, because private costs are linked to generalized agency backlogs that do not discriminate across sites within a region, it is conceivable that reforming federal land management policies can simultaneously reduce industry costs and improve environmental performance, for instance, by combining simpler permitting overall with more restrictive leasing in areas where marginal environmental damages are highest.

Our work contributes to several strands of literature. First, it relates to the theoretical literature on the economics of public versus private ownership, which emphasizes differences in incentives, monitoring, and organizational structure in the provision of goods and services (Hart, Shleifer, and Vishny, 1997; Besley and Ghatak, 2001). Second, it connects to research on transaction costs and investment behavior in oil and gas production, where regulatory processes, leasing institutions, and uncertainty can materially affect drilling decisions (Libecap and Wiggins, 1985; Anderson, Kellogg, and Salant, 2018; Covert and Sweeney, 2023). Third, we build on empirical studies that exploit exogenous patterns of land ownership as a natural experiment to study land use and resource development (Akee, 2009; Lewis, 2019; Leonard and Parker, 2021). More broadly, our findings contribute to a growing literature showing that administrative capacity and procedural complexity materially affect economic outcomes, even when formal policy rules are unchanged (Finan, Olken, and Pande, 2017; Best, Hjort, and Szakonyi, 2023; Herd and Moynihan, 2025).

This paper also serves to supplement an earlier retracted study that attempted to use the checkerboard to estimate additional costs of operating on federal land directly from expenditure data (Kunce, Gerking, and Morgan, 2002). Among other issues with the study, it was shown the expenditure data used was estimated without respect to land ownership and therefore could not possibly reveal the effect of federal ownership on costs (Gerking and Morgan, 2007). In contrast, our cost estimation strategy infers cost differences from observed drilling behavior at the well-level, thereby avoiding problematic assumptions about reported expenses.

We begin in section 2 by comparing federal and private contracts for oil and gas extraction and the additional processes involved when operating on federal land. Section 3 provides details on the checkerboard experiment, data, and our strategy for identifying the effects of federal ownership. Section 4.1 presents our findings regarding drilling investment and production, and section 4.2 presents a reduced-form model and estimate of the added cost of federal ownership that rationalizes these findings. Section 5 explores the mechanisms behind the results and the important role played by bureaucratic delay. Section 6 presents a brief discussion of the likely benefits of federal ownership and section 7 concludes.

2. Background

2.1. Contracting and Permitting on Private and Federal Land

In the U.S., mineral rights can be held by private individuals or by the government. Landowners, whether public or private, typically lease drilling rights to energy companies in exchange for a royalty payment—usually a fixed percentage of the gross production value (Fitzgerald and Rucker, 2014). For federal lands in our sample, the Bureau of Land Management (BLM) oversees this process under multiple-use mandates, managing auction procedures, permitting, and regulatory oversight.

Federal government parcels in Wyoming are managed by the BLM and are auctioned quarterly using a competitive sealed-bid first-price auction.[1] On BLM land, royalties paid to the U.S. government are 12.5% and lease stipulations are determined through codified BLM rules. On the other hand, royalty rates and other lease terms on private land are negotiated between the operator and landowner.

All drilling projects in Wyoming must obtain a state permit from The Wyoming Oil and Gas Conservation Commission (WOGCC). The WOGCC typically approves permits within 30 days and does not require site-specific environmental review. Operators on federal land, however, must secure both a state permit and a federal permit, extending the time between lease acquisition and well spud. The federal permitting process is subject to reviews under NEPA and related statutes. These procedures are designed to provide public benefits by mitigating environmental risks and ensuring safe operations, but they directly add costs and introduce delays and uncertainty into drilling operations. The oil and gas industry has noted these differences as reasons operators avoid investing in federal land (Flynn, 2017).

Starting in the late 1990s, new and updated Resource Management Plans (RMPs) in the BLM's regional field offices increased the scope and complexity of surface-use stipulations (Ruple and Capone, 2016). In the early 2000s, the number of federal permit applications surged alongside energy prices and the expansion of unconventional drilling. This increase in demand combined with more complex procedures overwhelmed BLM field offices, many of which did not scale staffing proportionately, and delays increased dramatically (GAO, 2013b; Kendall, 2019). In response, Congress enacted Section 390 of the Energy Policy Act of 2005 in an attempt to expedite the environmental review of oil and gas projects on federal lands (Capone and Ruple, 2017) including an increase in BLM permit filing fees. While an evaluation of this corrective action is beyond the scope of the present paper, our results show persistent effects well beyond the passage of this act.

2.2. Study Region: The Wyoming Checkerboard

Our empirical strategy relies on the historic allocation of land under the Pacific Railroad Acts of 1862–1871, which granted alternating square-mile sections to private railroads and retained the others in federal ownership. This generated a checkerboard pattern of surface and mineral rights that persists in the southern parts of Wyoming, a state that produces more gas from federal lands than any other US state, and likewise accounts for 36% of onshore well permit applications to the federal government.[2]

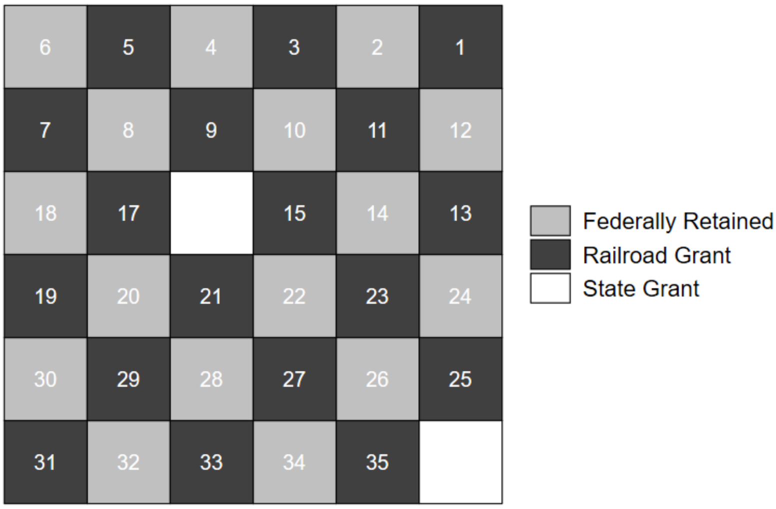
The acts granted title to every other section of land within twenty miles of either side of the Union-Pacific Railroad line that formed the first transcontinental railroad. The allocation grid is shown in Figure 1 for a single survey township, a six-mile by six-mile grid. Throughout the Wyoming checkerboard this township land allocation pattern was repeated. Approximately thirty years after the railroad grants were enacted, sections 16 and 36 in each Wyoming township were granted to the state "for the support of common schools" as part of its enabling act (Wyoming Admission Act, 26 Stat. 222 § 4 1890), and many of these sections were set aside as school trust lands. Because these state-assigned sections are subject to rules that do not apply to federal or private land, they are excluded from our analysis. As discussed in more detail below, these 19th century land ownership patterns have remained largely persistent to this day in the Wyoming checkerboard.

Today, the checkerboard-allocated area in Wyoming overlies the Green River Formation and underlying Mesozoic strata, where oil and gas production is heavily weighted toward natural gas. Oil and gas

[1]Unsold leases are available to be purchased non-competitively. Remaining parcels without a buyer are then recycled through the auction.

[2]BLM data for the years 2008-2017, available at: https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics

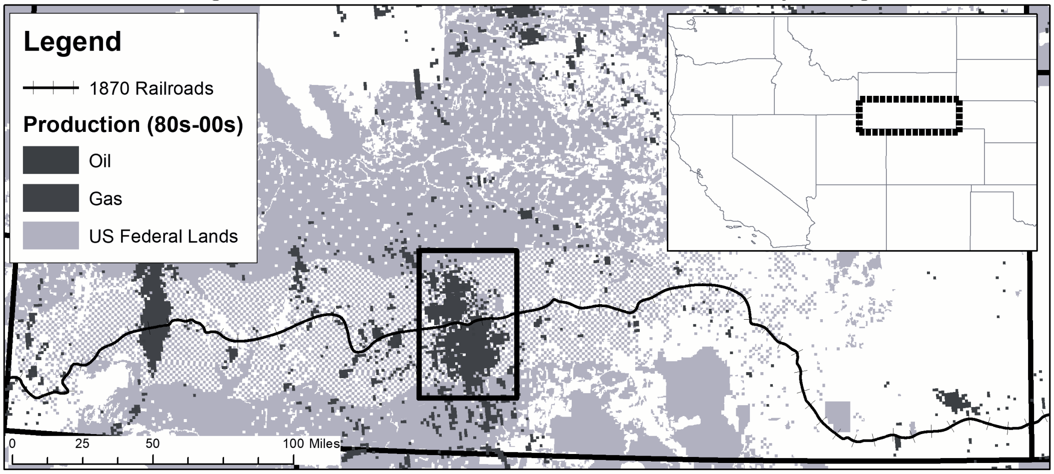
Figure 1: Checkerboard Assignment of Land and Subsurface Ownership



Notes: The typical Public Land Survey (PLSS) township consists 36 square-mile sections. Sections are numbered starting in the northeast corner in a boustrophedon pattern. Within the railroad grant boundaries in Wyoming, the Union-Pacific Railroad company was granted odd-numbered sections resulting in a checkerboard pattern of ownership. The state of Wyoming was later granted sections 16 and 36 and the remaining sections were retained by the federal government.

fields in this region are substantially larger than the sections that make up the checkerboard, ensuring ownership types are assigned to the same geological characteristics on average (DeBruin, 1989). Figure 2 shows the federal surface estate and oil and gas producing areas from 1980-2009 for the southern portion of Wyoming.[3] Our sample corresponds to the area directly north and south of the railroad path, with the primary oil and gas fields seen in the south-central and south-western portions of the state. When estimating the cost of federal ownership in section 4.2 we use a subset of this region over the Mesaverde reservoir indicated by the area within the rectangular box in figure 2. The Mesaverde is the most frequently drilled reservoir in our data, with much of this activity occurring during a boom period in the early 2000s.

Figure 2: Federal Land and Oil and Gas Wells in Wyoming



Notes: 2016 federal land ownership and the locations of oil and gas extraction for 1980-2009. Map created by the authors using data from "Railroads and the Making of Modern America" project at the University of Nebraska, Lincoln, National Atlas of the United States, and United States Geologic Survey. Black rectangle indicates bounding area for wells included in the Mesaverde sample.

[3]In the checkerboard, the surface estate corresponds nearly 1:1 with mineral right ownership.

3. Empirical Framework

3.1. Estimation Strategy

We estimate the effects of federal ownership on oil and gas production by contrasting average outcomes on sections assigned to federal land ownership (the treatment group) and private land ownership (the control group) within the railroad land grant boundaries. Specifically, we estimate the least-squares regression

$$Y_j = \alpha + \beta Even_j + e_j \quad (1)$$

where Y_j is a a cumulative oil and gas outcome at the section or well level indexed by j and the variable $Even_j$ is an indicator for an even-numbered section (i.e. sections assigned to federal ownership), and e_j is an error term. The parameter β represents the average effect of federal ownership if 1) the assigned ownership patterns remain when outcomes are determined and 2) all relevant factors existing prior to treatment assignment are balanced across ownership type.

To the extent the first assumption is not satisfied, β is more appropriately interpreted as an "intent-to-treat" effect.[4] We expect the second requirement to be satisfied by the checkerboard pattern of treatment assignment, which not only predates oil and gas discoveries in the region but very likely induces strong balance in spatial attributes critical for production, such as subsurface geology, across treatment assignment. We investigate both assumptions in section 3.3.

In addition to our main specification, we also report models with additional controls, including section size and survey township fixed effects. In analyses using production data with incomplete histories, we control for previous drilling activity on the section during the period in which production data is not observed (pre 1978). To better link our main analysis with our cost estimation, which is restricted to the Mesaverde Reservoir, we rerun analyses for the Mesaverde subsample when applicable and report the results in the appendix to show consistency with our main results. Throughout our analysis, we report heteroskedasticity-robust standard errors clustered at the township level.[5]

3.2. Data and Empirical Setting

3.2.1. Sample Definition

To construct our sample, we identify survey sections within the railroad grant boundaries using the 1870 railroads shapefile from the "Railroads and the Making of Modern America" project at the University of Nebraska, Lincoln, which includes the first established route of the Union Pacific Railroad (UPRR). While the original grants to UPRR were delineated based on a 20-mile buffer around the proposed railroad route, which we do not observe, it is evident from mapping the 1870 route that it closely follows the checkerboard strip with only small deviations. However, to safeguard against including sections outside the railroad grant boundaries, we only include sections within an 18-mile buffer around the 1870 route. The resulting sample consists of 14,390 sections.

3.2.2. Data Sources

Initial ownership assignment is determined by identifying even and odd-numbered sections using the BLM's geodatabase of cadastral reference features (CADNSDI). Data on current land/subsurface ownership come from two sources. We identify federal subsurface ownership using the 2014 Surface Management Agency (SMA) shapefile from the BLM and state subsurface ownership from the State Subsurface Ownership shapefile from the Wyoming Office of State Lands and Investments. Subsurface rights that are not federally or state owned are assumed to be privately owned.

Data on drilling, well production, and permits come from the Wyoming Oil and Gas Conservation Commission (WOGCC) and are publicly available on their website. While permitting and drilling data

[4] Most deviations from initial ownership assignment happen as a result of 19th and early 20th century homestead claims that also predate oil and gas discoveries in the region. Furthermore, nearly all changes from the initial assignment go in one direction: federal to private.

[5] Calculating Conley standard errors that account for spatial correlation in unobservables within a 10km bandwidth and no lags results in standard errors that are similar to those reported. For our main drilling results, Conley standard errors are 10 percent smaller on average and range from 31 percent smaller to 47 percent larger, but do not materially affect our conclusions. Results available upon request.

covers the full history of oil and gas operations in Wyoming , well-level production data is only available starting in 1978. Revenue measures are derived from observed production in a well's first three years and the drilling cost component is derived from observed drilling depth. We collect data on all outcome variables through December 31, 2019. Given that we only observe the outcomes of permit applications after a period of time, our analysis typically ends December 31, 2014, but uses subsequent years to construct production and delay measures. See data appendix A.1 for additional details as well as documentation of data pertaining to resource prices, special-status species, spills, and land characteristics.

3.3. Validity of Checkerboard Assignment

Table 1 shows the persistence of the original checkerboard assignment. In our checkerboard sample, 97 percent of odd sections remain privately owned, while 76 percent of federally assigned sections are retained by the federal government.[6]

Table 1: Current subsurface ownership by checkerboard assignment

Panel A: Wyoming Checkerboard Sample	Even Sections (Federally Retained)	Odd Sections (RR Grant)
Current Federal	76.01%	2.98%
Current Private	20.32%	96.77%
Current Other	3.66%	0.25%
Sections	6,775	7,615

Notes: Percentage of subsurface ownership type by even and odd sections. The sample in Panel A includes all Wyoming sections except for sections 16 and 36 within 18 miles of the 1870 route of the Union Pacific Railroad. When sections have more than one subsurface ownership type, ownership is assigned in proportion to area owned by each type within a section.

Table 2 displays average section-level characteristics and tests for balance across initial ownership assignment for the two samples. The table shows section characteristics are highly balanced across ownership type in both samples including elevation, standard deviation of elevation within a section (a measure of terrain ruggedness), whether the greater sage grouse has suitable habitat in the area, subsurface permeability, and proportion of sections within each of the BLM field office's administrative boundaries.

The only statistically significant difference across groups is average section size in the full sample, in which even sections are about a half-acre smaller than odd sections on average.[7] While we control for section size in our analysis, this difference is less than 0.1 percent of the mean and 1 percent of a standard deviation in section size.

Strikingly, the magnitudes of the differences between groups are consistently small. For each comparison, the difference in averages is less than 1 percent of the characteristic's standard deviation in the sample, and in most cases considerably smaller. Such a high degree of balance is surely due to the checkerboard assignment rule and should lead to substantially more precise treatment effect estimates than in a case where ownership type is allocated by simple random assignment.

4. Costs of Federal Ownership

4.1. Federal Effect on Drilling and Production

Table 3 shows regression results for cumulative drilling investment per section regressed on an indicator for an even section. The table reports a breakdown by time period for 1900-1949 and then five-year intervals through the end of 2014. Column 2 reports the raw differences showing that in the early periods, drilling

[6]Most deviations from initial ownership assignment went from federal to private ownership as a result of 19th and early 20th century homestead claims that also predate oil and gas discoveries in the region. In the Mesaverde sample, there are virtually no deviations from initial ownership assignment (see Table 8).

[7]Although PLSS sections were designed to be 640 acres, actual acreage can differ due to natural impediments, adjustments for the earth's curvature, and survey errors (Libecap, Lueck, and O'Grady, 2011). It was not uncommon for PLSS surveyors to correct errors systematically, such as at township corners, plausibly creating a link between section size and the pattern of ownership that is fixed across townships (Linklater, 2002).

Table 2: Section characteristics by checkerboard assignment

Panel A: Wyoming Checkerboard Sample	Even Sections (Federally retained)	Odd Sections (Railroad Grant)	Difference
Acres	629.93	630.50	-0.57***
			[0.20]
Mean elevation (m)	2,095	2,094	1.07
			[0.69]
Standard deviation of elevation (m)	13.18	13.19	-0.01
			[0.11]
Percentage with low permeability surface	45.37	45.45	-0.08
			[0.10]
Percentage with at least 10% sage grouse habitat	74.73	74.76	-0.030
			[0.06]
Percentage in Kemmerer field office	19.10	19.11	-0.01
			[0.07]
Percentage in Rawlins field office	59.51	59.47	0.04
			[0.08]
Percentage in Rock Springs field office	21.39	21.42	-0.03
			[0.07]
Observations	6,775	7,615	

Notes: Means and differences by initial ownership assignment. Robust standard errors for group differences are clustered at the survey township level and reported in brackets. $*** \ p < 0.01, ** \ p < 0.05, * \ p < 0.1$.

on federally assigned land exceeds drilling on railroad grant land, perhaps reflecting higher transaction costs of private contracting. This pattern generally holds until the late 1990s when drilling on private land begins catching up. By 2000 there is more drilling on private than federal land and this divergence expands rapidly throughout the rest of the sample period.[8]

By the end of 2014, there are 14 fewer wells drilled per 100 sections on federally assigned land than land allocated in the railroad grants, a statistically significant difference that amounts to a 19 percent reduction. The models reported in columns 3 and 4 add controls for section size and township fixed effects, respectively. The addition of these controls has a negligible impact on the federal effect estimate, which is expected given the high degree of covariate balance across even and odd sections.

The specific link between the checkerboard pattern of ownership and drilling investment becomes readily apparent when looking at cumulative outcomes averaged by section number. Figure 3 displays average drilling intensity for each of the federal and private allocated sections in a standard PLSS township. Sections are shaded according to the cumulative number of wells per section drilled during the sample period using a linear color scheme. In nearly all cases, the even-numbered sections are shaded lighter than their odd-numbered neighbors. Remarkably, the pattern of the 19th century railroad checkerboard is visible in investment outcomes determined over a century later.

Table 4 shows the differences in cumulative production and revenue per section from wells drilled from 1978-2014. Column 2 reports the raw differences, showing 5,809 fewer barrels of oil (20 percent lower), 21,27 fewer barrels of oil equivalent (BOE) of natural gas (13 percent lower), and approximately one million dollars less in revenue (15 percent lower) produced per section on federal land.

Column 3 reports effect estimates with controls for section size and township fixed effects, and Column 4 adds flexible nonparametric controls for both number of wells drilled and number of wells completed on the section prior to 1978 to account for our incomplete production data. As before, controlling for section size and township effects do not affect our results. It is also reassuring to see that including drilling investments made prior to 1978 do not meaningfully impact our estimates.

The federal-private divergence in drilling that arises in the 1990s and persists through the 2000s strongly suggests the additional costs of operating on federal land are deterring investment. These results offer a useful comparison point to Covert and Sweeney (2023) who use a natural experiment in Texas and find that allocating oil and gas leases through a centralized auction, much like the BLM does, increases production

[8]Figure 11 in the appendix plots the corresponding time-series of drilling flows for even and odd sections over the sample period.

Table 3: Federal Effect on Drilling Investment

	Cummulative Wells	Even Section Difference per 100 Sections		
	(1)	(2)	(3)	(4)
Through 1949	435	0.71**	0.73**	0.76***
		(0.29)	(0.29)	(0.28)
Through 1954	525	1.42***	1.43***	1.46***
		(0.46)	(0.46)	(0.45)
Through 1959	765	2.31***	2.32***	2.35***
		(0.54)	(0.54)	(0.53)
Through 1964	1232	3.60***	3.61***	3.64***
		(0.61)	(0.61)	(0.61)
Through 1969	1553	4.57***	4.58***	4.61***
		(0.71)	(0.71)	(0.70)
Through 1974	1954	5.38***	5.40***	5.43***
		(0.77)	(0.77)	(0.76)
Through 1979	2862	3.98***	3.99***	4.02***
		(0.88)	(0.88)	(0.87)
Through 1984	3682	3.97***	3.99***	4.02***
		(0.92)	(0.92)	(0.92)
Through 1989	3920	3.67***	3.68***	3.71***
		(0.98)	(0.98)	(0.98)
Through 1994	4700	3.49***	3.50***	3.53***
		(1.01)	(1.01)	(1.00)
Through 1999	5275	1.85*	1.87*	1.90*
		(1.12)	(1.12)	(1.11)
Through 2004	6456	-3.36**	-3.35**	-3.32**
		(1.55)	(1.55)	(1.55)
Through 2009	8345	-9.34***	-9.33***	-9.30***
		(2.85)	(2.85)	(2.85)
Through 2014	9581	-13.77***	-13.76***	-13.73***
		(3.10)	(3.10)	(3.10)
Controls				
Section Acres		No	Yes	Yes
Township Effects		No	No	Yes
Sections		14,390	14,390	14,390
Townships		491	491	491

Notes: Column 1 reports cumulative wells drilled in the sample region through each time period. Columns 2-4 report coefficient estimates on an even section indicator variable in a regression model of cumulative wells drilled per 100 sections with controls for section size and survey township effects in some specifications. Standard errors are clustered at the survey township level. $*** \ p < 0.01, ** \ p < 0.05, * \ p < 0.1$.

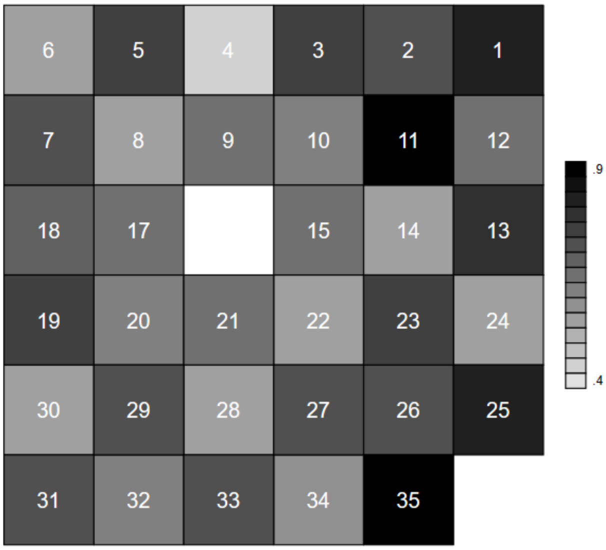
relative to private contracting suggesting centralized auctions reduce search and bargaining costs. Our findings imply the additional costs of operating on federal land after 2000, are larger than any potential benefits that may arise from the BLM's centralized leasing process.

4.2. Estimating the Implied Cost per Well to Operators

In this section, we present a reduced-form model to estimate the implied cost that rationalizes the persistent differences in drilling outcomes observed across otherwise comparable parcels. For the moment, we are agnostic about the mechanism behind the additional cost and treat our estimate as a summary of the combined effects of federal ownership on investment incentives.

While irreversible drilling decisions are inherently dynamic, we employ a static approach that focuses on persistent investment differences rather than explicitly incorporating optimal investment timing. The data used in our estimation sample come from the Mesaverde subsample where drilling activity is concentrated in a short boom and then drops sharply. This setting limits dynamic complications that would

Figure 3: Wells Drilled by Section Number



Notes: The figure displays average wells drilled per section by the end of 2014 for each section number in a typical survey township for the Wyoming checkerboard. Odd-numbered sections are railroad grant lands, and even-numbered sections are lands retained by the federal government. Sections 16 and 36 initially allocated to the state of Wyoming are omitted.

Table 4: Production per Section from Wells Drilled post 1978

	Odd Section Avg. (1)	Even Section Diff. (2)	Adjusted Diff. (3)	Adjusted Diff. (4)
Oil Production (Bbl)	28,450	-5,809*	-5,757*	-5,541*
		(3,255)	(3,315)	(3,324)
Gas Production (BOE)	158,674	-21,270**	-20,655*	-19,837*
		(10,484)	(10,589)	(10,258)
Revenue ($1,000s, Base: 2015)	5,446	-823.2**	-805.7**	-770.4**
		(381.0)	(386.2)	(372.8)
Controls				
Section Acreage		No	Yes	Yes
Survey Township Effects		No	Yes	Yes
O&G Investment prior to 1978		No	No	Yes
Observations (sections)		14,390	14,390	14,390

Notes: Columns 1-2 report means by initial ownership assignment. Columns 3-4 reports the difference associated with even sections with column 4 adjusting for survey township fixed effects. Robust standard errors are clustered at the survey township level and reported in parentheses. $*** \ p < 0.01, ** \ p < 0.05, * \ p < 0.1$.

otherwise arise in a more prolonged or multi-cycle development history. Cross-sectional drilling differences observed after the boom period should largely reflect foregone investment opportunities during periods of peak expected profitability.

We estimate observed drilling rates across townships as a function of estimated net revenue per well and contrast these functions across federal and private land. We infer the cost of federal ownership as the additional net revenue required to equalize drilling rate functions across type. Variation in the revenue component is derived from a well's observed production in its first three years and the drilling cost component is derived from observed drilling depths of producing wells. Because observed well production and drilling depths are outcomes affected by the checkerboard assignment, we also add additional restrictions when estimating expected net revenues to avoid compromising the checkerboard identification strategy.

4.2.1. *Estimation Sample: Mesaverde Reservoir*

Our cost estimation uses data from wells drilled over the Mesaverde reservoir, which account for approximately 63 percent of wells in our dataset. This restriction offers several advantages. First, current ownership over the Mesaverde exhibits near-perfect fidelity with initial surface ownership assignment (see table 8), minimizing concerns that subsequent land transactions confound federal–private comparisons. Second, Mesaverde development is highly concentrated in a short and relatively recent drilling boom in the early 2000s. This timing corresponds closely to the period in which we observe the largest divergence between federal and private drilling behavior. Finally, because our production data begin in 1978, restricting attention to Mesaverde wells ensures that we observe the full production history for nearly all wells in the estimation sample, whereas a substantial share of wells in the full dataset were drilled prior to 1978 and therefore have incomplete production records.

To ensure our sample boundaries are not a function of ownership type, we include all sections from any township with a well producing from the Mesaverde reservoir.[9]

4.2.2. *Reduced Form Model*

To start, we consider drilling behavior in a previously undeveloped oil and gas reservoir during a boom period starting at $t = 0$. The reservoir has varying productivity and depth across space and negligible common-pool spillovers. The reservoir is overlaid by a checkerboard of federal and private land in which square-mile sections are leased out to operators in a competitive market. Operators can drill a well on a section and do so if expected profit is positive.[10] Resource prices are exogenous and individual drilling decisions are uninfluenced by prior drilling behavior on nearby sections.

Expected profit from drilling a well in township i on section s with ownership type g is

$$\Pi^*_{isg} = (\bar{\pi}^*_i + e_s) - \theta Fed_{sg} - \gamma \tag{2}$$

where $\bar{\pi}^*_i + e_s$ is the expected revenue net of drilling and production costs for a well on section s in township i. Its component parts are a township average $\bar{\pi}^*_i$ and a mean-zero residual term that varies at the section level e_s, which is independent of ownership assignment. The variable Fed_g is an indicator for federal ownership and θ is the difference in expected cost per well incurred by the firm due to operating on federal land instead of private. The parameter θ is a composite of opportunity costs, including those that arise from constraints imposed by regulations or lost value from expected delay. The parameter γ captures average costs that are independent of the quantity extracted, the geology of the location, and ownership of the section.

Average expected revenue net of drilling costs for a well in township i is

$$\bar{\pi}^*_i = \frac{\sum_{s\in i} \pi^*_s}{n_i} = \frac{1}{n_i} \sum_{s\in i} \sum_{t=0} \beta_t (1-\tau_I)[(1-\tau_R)(P-X)Q_{st} - C_0(d_s)] \tag{3}$$

where n_i is the number of sections in township i and $\sum_{t=0} \beta_t (P-X) Q_{st}$ represents the average expected present-value revenue from production (less variable costs) over the lifetime of a well on section s. P and X are the expected price and cost per unit of production respectively, which for simplicity and transparency, are assumed to be constant throughout the life of the well. Q_{st} is the expected resource production from a well in section s at time t, and β_t is a discount factor. The parameter τ_R represents the sum of the royalty rate paid to the landowner plus the rate of other revenue taxes and τ_I represents an income tax rate. The firm faces drilling costs $C_0(d_s)$ where d_s is the depth of the reservoir under section s and $C_0'(d_s) > 0$.

A firm drills a well on section s if $\Pi^*_{sg} > 0$ and does nothing otherwise. If $\theta > 0$, a profit-maximizing firm will require a higher minimum π^* to drill on federal land to compensate for additional costs. We define the minimum values to drill as $\underline{\pi}^P$ and $\underline{\pi}^F$ for private and federal ownership, respectively. This gives three

[9] In rare cases, a few wells identified as producing from the Mesaverde reservoir are spatially isolated from the others. To keep the area relatively contiguous, and to avoid possible data entry errors, we omit wells outside of a coordinate bounding box shown in Figure 2.

[10] We choose the "section" as the unit of analysis to simplify the model. The mechanics of the model are unchanged if we instead define the decision to drill at the 40-acre spacing unit.

intervals of section quality in our sample, $\pi_s^* \in (-\infty, \underline{\pi}^P]$ no well is drilled on the section regardless of ownership, for $\pi_s^* \in (\underline{\pi}^P, \underline{\pi}^F]$ a well is drilled only if the section is privately owned, and for $\pi_s^* \in (\underline{\pi}^F, \infty)$ a well is always drilled on the section. Because ownership assignment is orthogonal to section-level variation in geology, townships that include some sections in which $\pi_s^* \in (\underline{\pi}^P, \underline{\pi}^F]$ are expected to have a lower rate of sections drilled on federal land compared to private.

Our cost estimation approach can be understood by considering two townships j and k where the probability of drilling on a federal section in j matches the probability of drilling on a private section in k. The probability that a firm drills on a section of ownership type g in township i is

$$\begin{aligned} p_{ig} &= Pr[Drill_{isg} = 1 \mid Fed_{sg}] \\ &= Pr[\bar{\pi}_i^* + e_s - \gamma - \theta Fed_{sg} > 0] \\ &= Pr[e_s > -1 \times (\bar{\pi}_i^* + -\gamma - \theta Fed_{sg}]). \end{aligned} \tag{4}$$

The expected cost of federal ownership equals the difference in the average expected net revenue from drilling on a section in townships j and k

$$\theta = \bar{\pi}_j^* - \bar{\pi}_k^* \quad \text{when } p_{jF} = p_{kP}. \tag{5}$$

In the next subsections, we outline how we measure $\bar{\pi}_i^*$ and the assumptions we make to compute a sample-wide approximation of θ.

4.2.3. *Measuring expected net revenue at the township level*

We construct an estimate of $\bar{\pi}_i^*$ using historical data on prices and production and drilling depth from wells on odd-numbered sections. All monetary values are adjusted for inflation with a base year of 2015. We calculate the price of barrel of oil equivalent (BOE) as a weighted average of Wyoming crude oil first purchase price (15 percent) and natural gas prices from the Opal hub purchased from Natural Gas Intelligence (85 percent) to reflect the fraction of energy coming from each fuel type in our sample. We set a constant real price per BOE at \$64 for all periods t based on the averaged price over 2005 and 2006. This period represents the peak estimated value of a well in the Mesaverde reservoir based on a two-year average.[11] Over the same period, the average cost per drilling foot is estimated to be \$377 (U.S. Energy Information Administration, 2025). We estimate post-production costs at \$3.40 per BOE based on federal sales data (U.S. Department of the Interior, Office of Natural Resources Revenue, 2026) from 2013, the earliest year available.

The expected production profile of a well is estimated from observed production in its first three years and projected forward using decline curve analysis as described in the data appendix A.1. Royalty rates are assumed to follow the federal rate of 12.5 percent for all parcels (see section 5.4 for discussion). Wyoming state severance tax is set to 6 percent and county ad valorem taxes at 6.2 percent. A federal corporate tax of 35 percent is applied to net production revenue minus drilling costs. We assume a discount rate of 10 percent.

We denote observed net revenue at the section level as π_{is}.[12] However, π_{is} is unobserved when $\bar{\pi}_i^* + e_{is} \leq \underline{\pi}^g$. Therefore, the average of π_{is} is expected to overestimate $\bar{\pi}_i^*$ for townships with undrilled sections and the magnitude of this bias is inversely related to $\bar{\pi}_i^*$. Because our estimation strategy relies on differences in $\bar{\pi}_i^*$ across townships, this latter fact prevents us from simply using the average of observed returns in a township as a measure of $\bar{\pi}_i^*$. We instead use an unbiased measure of the median net revenue in township i as a proxy for $\bar{\pi}_i^*$.

We first define a new censored variable at the section level equal to observed net revenue π_{is} and assign the minimum π_{is} in a township to sections that have not been drilled.

[11] The sensitivity of our results to changes in the price assumption is discussed at the end of this section.

[12] When odd sections have more than one well, we use the average production per well to calculate π_{is}. Results are largely unaffected if we instead estimate revenue using only the first well drilled on each section or if we use even-numbered sections.

$$\tilde{\pi}_{is} = \begin{cases} \pi_{is}, & \text{when } \pi^*_{is} = \bar{\pi}^*_i + e_{is} > \underline{\pi}^g \\ \min_{s \in i}[\pi_{is}], & \text{otherwise.} \end{cases} \tag{6}$$

We then use the median of $\tilde{\pi}_{is}$ as our estimate of the median of π^*_{is}. To help ensure the censored part of the variable does not bias our estimate of median net revenue, we further restrict our estimation sample to townships in which more than half the sections have been drilled.

Our approach does not require the township medians and means of π_{is} to match, but rather the difference in the medians between townships to be a credible estimate of the difference in the means. To this end, we investigate a sample of townships in which all sections have been drilled. A simple linear regression of the mean π_{is} on median π_{is} in this sample has an R-squared of 0.84 and a slope estimate of 0.93, indicating a \$1 change in the median net revenue for a township is associated with a \$0.93 change in the mean. Assuming this basic pattern holds across partially drilled townships with less appealing prospects, these results imply our approach will tend to overestimate expected federal costs by about 7.5 percent.

4.2.4. Choice of Drilling Outcome

We model the probability that at least two wells on a section are drilled rather than the probability that any section is drilled. We do this for two reasons. The first is that sections with a single well may have been drilled for exploration and are not profitable enough to justify further development of the section. Exploratory wells collect valuable information on regional productivity and are not simply drilled for their expected returns. Lewis (2019) uses a sequential model of exploratory drilling to show that when the value of information is high, even small differences in cost between ownership types can lead to substantial differences in drilling rates when parcels of both types are in close proximity. A second well on a section, on the other hand, provides limited information value.

The second issue arises from the requirement that federal leases must have an active producing well on a section to maintain the lease after its primary term expires. This "held by production" rule gives operators an incentive to drill a single well on a section to hold the lease even when expected returns are negative at the time of drilling (Herrnstadt, Kellogg, and Lewis, 2020). Though private leases often have a similar requirement, focusing on the probability a second well is drilled alleviates concerns about differences in this lease contingency. While it's plausible having the first well on a section lowers the costs of drilling a second, we expect the cost reduction to be relatively small when the original well is not part of a larger development plan, as is typically the case with exploratory wells or wells drilled specifically to hold the lease.

4.2.5. Cost Estimation and Results

To back out a sample-wide approximation of θ using regression, we assume e_{is} follows a logistic distribution and estimate the following probability model for the decision to drill two wells on a section

$$p_{isg} = Pr[Drill2_{isg} = 1] = \frac{e^{\alpha + \beta_\pi \bar{\pi}^*_i + \beta_F Fed_{sg}}}{1 + e^{\alpha + \beta_\pi \bar{\pi}^*_i + \beta_F Fed_{sg}}} \tag{7}$$

where $Drill2_{isg}$ is an indicator for whether a section in our sample has at least two wells. The cost parameter can then be recovered as the coefficient ratio

$$-\frac{\beta_F}{\beta_\pi} = \theta \tag{8}$$

This interpretation follows because the latent profit function is linear in π^*_i and Fed_s, so the ratio $-\frac{\beta_F}{\beta_\pi}$ converts the effect of federal ownership into dollar terms—the additional expected present value net revenue (after taxes) required to leave the drilling decision unchanged.

Table 5, Panel A reports the coefficient estimates for equation 7. Standard errors clustered at the township level are reported in brackets. In column 1, we see the coefficient estimates for both ownership assignment, where we expect even sections to reduce the probability of drilling, and expected net revenue, which we expect to increase the probability of drilling, are highly significant and in the expected directions.

Our estimate of the additional cost of operating a well on federal land is $512,000 with a 95% confidence interval [$77,000 , $947,000] when standard errors are clustered at the township level as reported in Column 1 of Panel B. Columns 2 and 3 do not assume a specific cost per drilling foot and report results for regressions on median revenue while including linear and quadratic controls for median well depth, respectively. The model in column 2 with a linear control for well depth yields the most conservative cost estimate across the three models at $463,000 per well. However, we prefer the estimate in column 1 due to its smaller standard error.

Table 5: Back of the Envelope Cost Estimation

	(1)	(2)	(3)
Panel A: Logistic Regression Coefficients			
Two or More Wells Drilled on a Section (0,1)			
Even Section (0,1)	-0.529	-0.527	-0.532
	[0.213]**	[0.213]**	[0.212]**
Median Net Revenue (Township)	1.033		
	[0.186]***		
Median Revenue (Township)		1.136	1.107
		[0.268]***	[0.277]***
Control for Median Depth	No	Linear	Quadratic
Sections	686	686	686
Townships	22	22	22
Panel B: Implied Federal Cost per Well			
$\hat{\theta}$ (millions, $2015)	0.512	0.463	0.480
	[0.222]**	[0.234]**	[0.242]**

Notes: Panel A reports estimated coefficients from a logistic regression model of the probability at least two wells are drilled on a section in the Mesaverde sample. Column 1 reports results using township-level median after-tax net revenue. Columns 2 and 3 do not assume a specific cost per drilling foot and report results for regressions on median after-tax revenue while including linear and quadratic controls for median well depth, respectively. Panel B reports estimates of the cost of operating on federal land derived from the model coefficients. Monetary values are measured in millions of dollars (base year 2015). Robust standard errors clustered at the township level are reported in brackets. $*** \ p < 0.01, ** \ p < 0.05, * \ p < 0.1$.

Adjusting our preferred estimate for the potential bias introduced by using a township's median net revenue instead of mean, leaves us with a cost estimate of $476,000 per well, which represents 14% of the average after-tax drilling cost per well in the estimation sample.[13]

Figure 4 visualizes our estimation procedure from Column 1 of Table 5 by plotting the fitted probability of drilling two wells on a section over a township's expected net revenue for each ownership type.[14] The points on the graph represent observed drilling rates by township and ownership type and their size is proportional to the number of sections in the township used in the sample. Our cost estimate per well corresponds to the horizontal distance between the private and federal probability functions.

We explore the sensitivity of our cost estimate to a range of resource price assumptions. Assuming 40 and 80 per BOE yields cost estimates of $\$347,000$ and $\$625,000$, respectively. The full sensitivity analysis with 95 percent confidence intervals is plotted in figure 15. Additional robustness checks are included in the appendix. In table 13 we show specifications using probit and a linear probability model. Results are similar in both cases with cost estimates slightly higher across both alternative models.

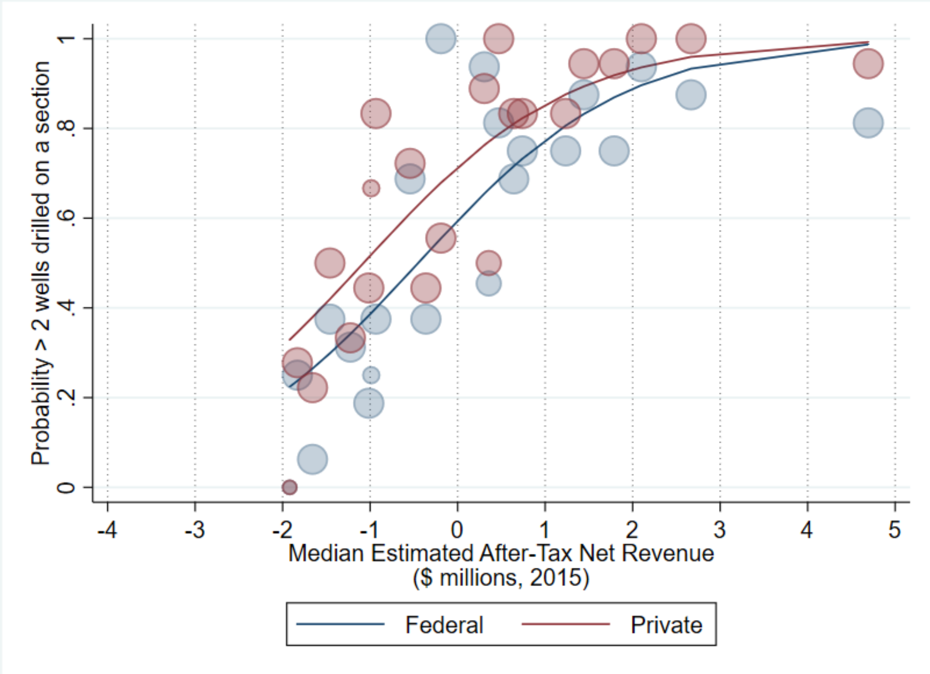
5. Sources of Added Cost on Federal Land

In this section, we analyze the mechanisms contributing to additional costs faced by operators on federal land. While we find suggestive evidence that stricter environmental regulation and increases in permitting

[13] We multiply the estimate from table 5 panel B, column 1 by the 0.93 adjustment, as described above.

[14] A similar graph using nonparametric regression is shown in figure 14.

Figure 4: Probability a Section has Two Wells



Notes: Fitted logistic regression lines of the probability of drilling two wells over median estimated after-tax net revenue conditional on ownership type overlaid on the underlying township proportions.

delay both add cost, permitting delay, likely exacerbated by more complex regulation, stands out as the primary driver of our results. At the end of the section, we argue that alternative explanations, including differences in royalty rates, land closures, and bonding requirements across federal and private ownership, are inconsistent with our results.

5.1. The Role of Permitting Delay

Longer and more open-ended permitting processes impose costs on operators. Lengthier processes require more labor, can depreciate project-specific human capital, delay profit, and reduce an operator's ability to take advantage of changing market conditions. Processes with many touch points also naturally lead to greater uncertainty in the duration of these processes, which can complicate the coordination of equipment and personnel and increase uncertainty about market conditions at the time of drilling.

In this section, we leverage the checkerboard setting to create a novel measure of delay in the federal permitting process to quantify its extent and its close relationship with the federal-private difference in drilling investment we observe over time. To drill a well on federal land, operators must submit an application for a permit to drill (APD) to the BLM for each proposed well. While the BLM publishes aggregate statistics on APD processing times, they do not release well-level information. In a 2013 report, the Government Accountability Office attempted to analyze the length of permitting delays: "GAO found that BLM's central oil and gas database was missing certain data... Without complete data on approved APDs, GAO could not perform a comprehensive assessment of the amount of time it took BLM to process APDs from their date of receipt to date of approval. (GAO, 2013a)"

While BLM permit approval is required only on federal lands, all wells drilled in Wyoming require a state drilling permit approved by the WOGCC. For any proposed well in which there is a state APD, we are able to observe the dates of permit application, permit approval, and well spud (the date drilling begins). Because operators on federal land must also obtain BLM approval before drilling, additional delay caused by the federal permitting process should be captured in the gap between WOGCC permit approval and spud date.

WOGCC permits expire if drilling has not started within one year of approval.[15] It is fairly common for operators to reapply for a state permit if they fail to drill a well the first year. In these cases, one well will be linked to multiple permits. We use the date of the first application approval by the WOGCC as the permit approval date. For wells that are ultimately drilled, we use the number of days from permit application to spud as our measure of delay. Delay is calculated for all wells with permit application information from 1900-2014. Our well production records continue through 2019, providing a minimum five-year observation on whether wells are ever drilled.[16]

We have no reason to suspect the process of state permit approval differs by land ownership type and we find no evidence of differences in our data. The top-left panel of Figure 5 plots the federal-private difference in the median number of days between application and approval for state permits at five-year increments.[17] The plot shows no meaningful differences in approval timing between federal and private land throughout the sample period.

On the other hand, if there is further delay in the federal permitting process, we should expect longer intervals between permit application and spud on federal lands. The top-right graph of Figure 5 is on the same scale as the top-left and shows the federal-private difference in median time to spud from the state permit application date. Prior to 1995, there is little difference in time to spud across ownership types. However, over the last 20 years of the sample, the additional median drilling delay on federal land increases substantially to approximately half a year. This timing closely aligns with trends in BLM permit processing times seen in aggregated data.

The bottom row of Figure 5 shows the difference in the interquartile range (IQR) of the duration of each stage. As with the median, we see negligible differences in the IQR of time to state approval across ownership types, but the IQR of time to spud is much greater on federal land starting in the mid-1990s. Overall, the median and IQR are highly correlated over time, suggesting that periods with longer expected delays will also have greater uncertainty about delay length.

Table 6 provides statistical tests of mean differences in cumulative permitting outcomes across ownership type.[18] Consistent with our drilling investment results, we find significantly fewer state APDs submitted on federal sections. For APDs submitted, the state process shows no statistically distinguishable differences in approval rates and average approval times across ownership type. However, federal ownership significantly reduces the chances that an approved state APD goes to spud by an estimated 11-13 percentage points, showing that operators not only propose fewer projects on federal land but also abandon proposed projects at a higher rate. For wells that are drilled, the average time from state permit application to spud is 158 days on private land and 272 days on federal land.

Figure 6 (top panel) shows the median delay in days between the time between state APD and spud date for federally and privately assigned sections in the checkerboard. The data are aggregated into five-year intervals, consistent with Figure 5, and reveal a similar divergence in permitting delay between federal and private land beginning in the late 1990s. This divergence in delay can be directly compared to the divergence in drilling activity shown in the bottom panel. The close temporal correspondence between these patterns provides a striking visual association between permitting delay and investment behavior.

Nevertheless, it remains unclear whether delay itself is the primary mechanism causing the federal-private divergence in drilling or whether it reflects other, costlier regulatory constraints associated with federal land. In the following two subsections, we examine the extent to which direct regulatory costs can be distinguished from permitting delay and assess whether observed delays are driven by administrative backlogs rather than site-specific factors.

5.2. Special-status Species Regulation

We first examine whether spatially specific regulations affect the cross-sectional pattern of drilling and permitting delays. In particular, we exploit the fact that the BLM has stricter lease stipulations in

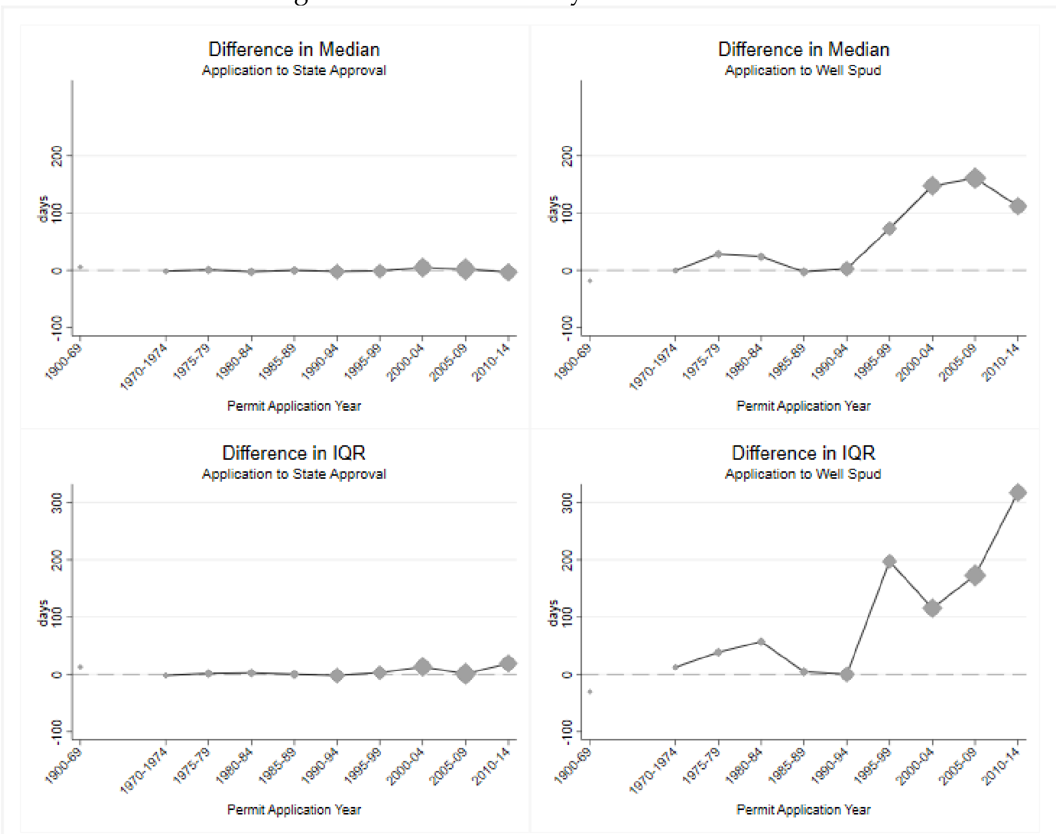
[15]Starting in January 2016 the WOGCC began allowing operators two years to start drilling before each permit expires.

[16]Of the 9,033 wells in the dataset for which we observe the time from permit application to spud, only 43 take longer than five years to spud.

[17]We occasionally encounter an extraordinarily long time between application and approval and/or application and spud dates in the WOGCC data (e.g., 15 years) with an unclear explanation as to why, therefore we choose to plot medians instead of means.

[18]To prevent extreme values from dominating the analysis, we top-censor durations longer than 730 days after state approval.

Figure 5: Additional Delay on Federal Lands



Notes: The top row shows plots the federal-private difference in median duration for a particular project stage: the time between state permit application to state approval, left, and from state permit application to spud, right. The bottom row shows the difference in the interquartile range (IQR) of duration for the same stages. The sample includes all wells with permit applications filed by 12/31/2014 and spud dates by 12/31/2019. Points are scaled by number of wells drilled by period of permit application.

ecologically sensitive areas. Specifically, we estimate whether the cumulative federal-private differential in drilling and permitting delay are correlated with the presence of special-status species. Unlike the checkerboard ownership assignment, we do not expect the location of these ecologically sensitive areas to be exogenous, therefore we treat the analysis in this section as exploratory rather than causal.

In 2001, the Wyoming BLM approved a list of "sensitive species" on BLM lands within the state and set rules to manage these species and their habitats proactively. Sensitive species are ones native to BLM lands and either declining or dependent on threatened habitats. One sensitive species, the greater sage grouse, is given disproportionate attention in Wyoming BLM documents, particularly during the 2000s, therefore we treat it separately in the analysis below.[19]

It's important to note that the ESA applies to both federal and private land and therefore may not add costs to operating on federal land specifically. For instance, the Section 9 "take" liability of the ESA applies to operators regardless of who owns the land. Section 7 of the ESA, however, requires projects within the "federal nexus" to have a consultation from US Fish and Wildlife, and the BLM's permitting process falls within that nexus. It is also plausible that monitoring and enforcement of the ESA differ on federal land. For these reasons, we also measure areas where endangered species are present.

[19]The sage grouse was first considered for listing under the ESA in 2002 and in 2005 the EPA issued a finding of "not warranted." In 2010, after appeal and reconsideration, the status of the sage grouse was changed to "warranted but precluded (SWSWG, 2013).

Table 6: Federal Effect on Permitting and Delays

	Odd Avg. (1)	Even Diff. (2)	Adjusted Diff. (3)
Proposed wells per section	0.699	-0.113***	-0.113***
Universe: Sections		(0.029)	(0.030)
Observations		14390	14390
Probability state APD is approved	0.987	0.00182	0.00105
Universe: Proposed wells		(0.00391)	(0.00383)
Observations		9300	9300
Days from state appl. to approval	35.41	0.953	1.255
Universe: Approved state APDs		(3.072)	(2.189)
Observations		9178	9178
Probability state APD goes to spud	0.717	-0.111***	-0.129***
Universe: Proposed wells		(0.025)	(0.024)
Observations		9300	9300
Days from state appl. to well spud	157.7	114.2***	117.4***
Universe: State APDs going to spud		(13.9)	(14.2)
Observations		6215	6215
Controls			
Survey Township Effects		No	Yes

Notes: The table reports regression slopes for permitting outcomes on an indicator for an even section over the history of oil and gas activity on the Wyoming checkerboard. Column 3 reports results controlling for township fixed effects. A proposed well is any well plan with at least one APD submitted to the WOGCC. Time between application and approval is top censored at 730 days. Time between application and well spud is top-censored at 730 days after state approval. Statistical significance using standard errors clusterd at the township level are indicated as $*** \ p < 0.01, ** \ p < 0.05, * \ p < 0.1$.

We estimate township-level regressions of drilling and permitting delay differentials on the presence of special-status species in that area using data from the Wyoming Natural Diversity Database.

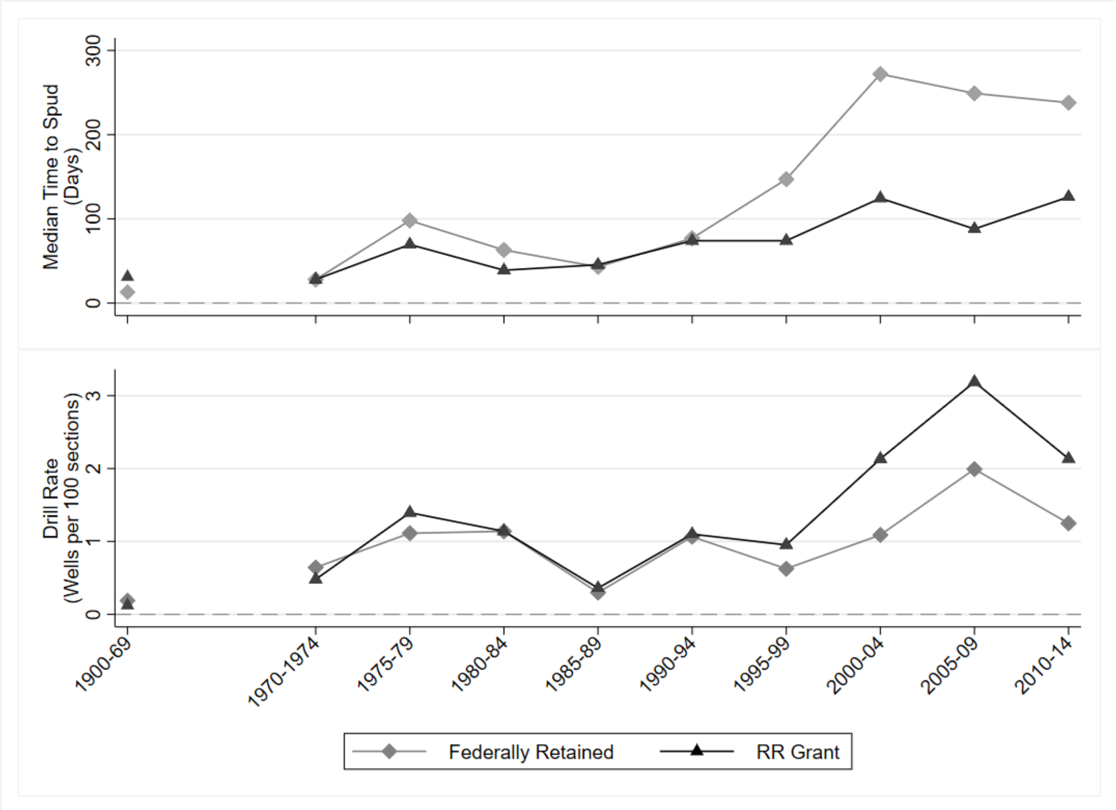
$$\Delta_{F-P}\bar{Y}_i = \alpha + \gamma_1 SensitiveSpecies_i + \gamma_2 SageGrouse_i + \gamma_3 EndangeredSpecies_i + \sum_h \delta_h Control_{hi} + e_i \quad (9)$$

where $\Delta_{F-P}\bar{Y}_i$ is the federal-private difference in township i, $SensitiveSpecies_i$ is the count of BLM-designated sensitive species in township i, $SageGrouse_i$ indicates the presence of the Greater Sage Grouse, and $EndangeredSpecies_i$ is and indicator for whether a species listed under the ESA is present in the township.[20] The set of control variables used include township averages of elevation, terrain ruggedness, and parcel size, and indicators for low permeability and BLM region. e_i is an error term. We expect the parameters γ_1, γ_2, and γ_3, to be negative if federal ownership is a stronger deterrent to drilling in areas with the corresponding special-status species. Table 7 reports the estimation results.

Columns 1 and 2 show a negative and statistically significant correlation between the federal-private differential and the sensitive species count. This relationship is consistent with operators avoiding federal land due to stricter regulations on this category of species. Sage grouse areas do not have statistically significant correlations with the federal-private drilling differential in either model. Interestingly, the federal-private drilling differential is positively correlated with the presence of endangered species in an area. The relationship is statistically significant only in the model without controls, but it is large enough to offset the differential observed in our baseline model. Although we caution against a causal interpretation of this relationship, a plausible mechanism is that litigation risk related to the ESA may be reduced by going

[20] We only count species listed in 2022, the time of data retrieval. Though the bald eagle was listed as endangered until 2007, it is counted as a sensitive rather than endangered species in our data.

Figure 6: Delay and Drilling



Notes: The top panel plots the median number of days from WOGCC permit application to well spud for all wells spudded by application date for five year intervals. The bottom panel plots annual wells spudded per 100 sections based on the initial checkerboard assignment of land ownership for the entire checkerboard.

Table 7: Federal-Private Differences in Outcomes by Wildlife Areas

	Federal difference in wells drilled per section		Federal difference in days until spud	
	(1)	(2)	(3)	(4)
Species present				
Sensitive species (count)	-0.12**	-0.13**	-5.36	-5.5
	[0.05]	[0.06]	[9.93]	[9.96]
Sage Grouse (0,1)	0.02	0.24	6.31	-80.71
	[0.32]	[0.47]	[100.79]	[123.36]
Endangered species (0,1)	0.78**	0.43	24.26	14.37
	[0.37]	[0.35]	[43.22]	[42.85]
Controls	No	Yes	No	Yes
Observations	146	146	139	139
R^2	0.05	0.11	<0.01	0.09

Notes: The table reports slope coefficient estimates from 9 using township-level data. Robust standard errors are reported in brackets below. Columns 1 and 2 show regressions of the federal-private difference in average wells per section for townships with drilling activity. Columns 3 and 4 show regressions of the federal-private difference in median permitting delay for townships in which at least one state APD per ownership type went to spud during our sample period. Delay regressions are weighted by the total number of state APDs filed in the township.

through the BLM's permitting process, thereby attracting operators to federal land in these areas relative to private land.

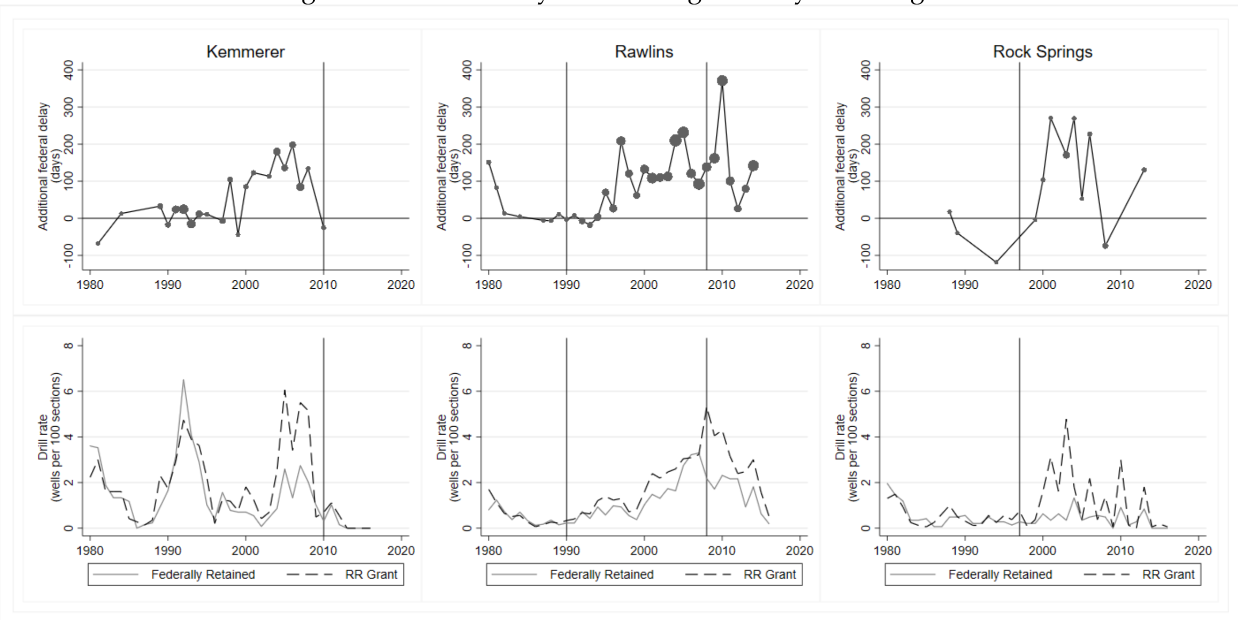
In contrast, Columns 3 and 4 do not provide evidence that permitting delays are longer (or shorter) in these areas. The model of delay without controls has almost no predictive power ($R^2 < 0.01$), indicating that the spatial pattern of special-status species is unrelated to federal permitting delays. Overall, these cross-sectional results are suggestive of a direct effect of environmental regulation on drilling, rather than an indirect effect through increased delays. However, because the spatial variation in permitting delay is limited we do not expect cross-sectional analysis to capture changes that arise from regional or agency-wide backlogs.

5.3. BLM Region Analysis

In this section, we examine time trends in drilling and permitting delays at the regional level. Our data cover three BLM regions, Kemmerer, Rawlins, and Rock Springs. Each region has its own field office responsible for issuing oil and gas permits on BLM managed land. The permitting process is guided by region-specific Resource Management Plans (RMPs). Major revisions to RMPs starting in the 1990s added complexity to the permitting process and have been cited as an explanation for the rise in BLM permitting delays (Humphries, 2018). In our sample, the Rawlins region revised its RMP in 1990 and more substantially in 2008, the Rock Springs region had a major revision in 1997, and Kemmerer region did not revise its RMP until 2010.

Figure 7 plots regional-level time-series starting in 1980 of our measure of additional federal permitting delay (top row) and driling rates by ownership type (bottom row). It shows the rise of federal delay generally coincides with times of high demand. In the Rawlins and Rock Springs regions, an increase in federal delay begins almost immediately following revisions to their RMPs. This pattern supports the claim that longer delays are due to the increased process complexity in updated RMPs.

Figure 7: Federal Delay and Drilling Rates by BLM Region



Notes: Each column corresponds to a BLM region within our data. The top row of plots shows annual measures of federal-private difference in median permitting delay for wells proposed within a BLM region (minimum of 5 APDs per type per year). Points are weighted by the number of APDs that went to spud. Regions correspond to the locations of the proposed wells, not the field offices where the permits were processed. The bottom row of plots shows annual flows of wells drilled per 100 sections by ownership assignment for each region. Vertical lines indicate when RMPs were revised for that region: Kemmerer 2010, Rawlins 1990 and 2008, Rock Springs 1997.

The pattern of delay in the Kemmerer region provides additional insight. First, we note that the Kemmerer region experienced two major waves of permit demand: one in the early 1990s and another in the early 2000s. Consistent with a more straightforward permitting process, we can see the Kemmerer field office was able to manage the first wave without much delay. However, we see a large increase in federal delay during the second wave. Although this second periodpredates revisions to Kemmerer's RMP, it coincides with a rise in workload sharing between field offices. Starting in the late 1990s in Wyoming, and all states by 2005, it became common practice for the BLM to reallocate NEPA and technical staff within a state when demand for permits increased (U.S. Department of the Interior, Office of Inspector General, 2004; Humphries, 2018). It is plausible then that the delays in the Kemmerer region in the 2000s are reflecting overflow from nearby field offices, including ones that had already revised their RMPs, such as Rock Springs and Rawlins.[21]

In each case, we find federal delay is closely correlated with a relative decrease in drilling investment on federal land. Because federal delay in Rawlins and Rock Springs follow changes to their RMPs, the drilling deterrence observed on federal land is consistent with both a bureaucratic delay mechanism and a regulatory stringency mechanism. However, the drilling pattern in the Kemmerer region appears to be best explained by the permitting process itself. During the first wave in the demand for permits in Kemmerer, there is no additional federal delay and drilling rates are very similar on private and federal land. During the second wave, there is substantial federal delay and drilling rates on federal land fall well behind rates on private land. This latter period is key, because it predates Kemmerer's RMP revision, and therefore the federal-private drilling divergence cannot be explained by an increase in regulatory stringency.

To summarize our results thus far, we find 1) temporal trends in federal delay and the federal-private drilling divergence are highly correlated over the sample period (section 5.1), 2) federal delay is not concentrated in ecologically sensitive areas (section 5.2), 3) federal delay rises with spikes in permit demand but only after RMPs are revised or workload sharing across regions becomes common, 4) a sharp increase in federal delay in the Kemmerer region (plausibly explained by permit overflow from other regions) coincide with a sharp reduction in drilling on federal land, absent regional rule changes. While regulatory stringency likely plays some role in deterring drilling on federal land (as suggested in section 5.2), the majority of the evidence strongly supports the view that generalized permitting delays and their associated uncertainty, likely exacerbated by regulatory complexity, are the dominant mechanism driving the observed divergence in investment.

Finally, we note that some delay costs cannot be reflected in the cost estimate presented in section 4.2 because they do not result in persistent differences in drilling investment. When a well is still expected to be profitable despite delays, for instance, drilling may proceed at a later time. This investment re-timing leads to lost interest and likely lost revenues if prices recede during the delay period. However, if drilling occurs by the end of our sample period, these re-timing costs would not be captured in our static cost estimate. Furthermore, our results in section 5.1 show that federal land is associated with a higher rate of proposed projects that never go to spud. When delays in the permitting process lead operators to abandon projects before drilling, the observed drilling outcome is the same as if the project were never started. Therefore, any lost permitting fees, labor costs, and missed opportunities for alternative investments will not be reflected in our estimate. Both of these limitations in our cost estimates lead to an underestimate of the full cost of delay.

5.4. Alternative Explanations

The systemic allocation and resulting balance between government and privately owned sections in our empirical setting allows us to make a strong causal claim about ownership and outcomes: federal ownership decreases drilling and production from the mid-1990s onward. Our analysis points to the length and uncertainty in the federal permitting process and, to a lesser extent, stricter regulation, as an explanation for this divergence. This explanation is also consistent with GAO reports, private discussions and public comments by firms and trade groups. The relative increase in delay on federal land coincides closely with reductions in drilling and output. However, we do not observe a counterfactual scenario where the increase in delay does not occur. In this section, we discuss other potential mechanisms by which federal ownership could lead to less investment and production.

5.4.1. Royalty Differential

Our model assumes royalty rates are the same across federal and private land. In practice, the royalty rate on all federal leases is fixed at 12.5 percent, but rates on private leases are negotiable. If federal royalty rates are systematically higher than private rates, this could lead to a relative decrease in production and a relative increase in the average quality of well locations on federal land.

[21] We cannot evaluate delay changes after Kemmerer's RMP revision, because permit applications in the Kemmerer region sharply drop after 2010 and our our measurement of delay is restricted to region-years in which private and federal land had at least 5 APDs.

Fitzgerald and Rucker (2014) find that onshore oil and gas royalty rates on privately owned minerals in the US were 13.5 percent for oil and 11.8 percent for natural gas in 2011-2012. Brown, Fitzgerald, and Weber (2019) find a combined average of 15.3%. The U.S. Price Lease Report, the most comprehensive source of private royalty rates, from March/April of 2005, indicates private royalty rates equal or surpass the federal rate. The highest reported private royalty rate for counties in our sample is 18.75 percent, and the minimum is equal to the federal rate of 12.5 percent. Taken together, we do not suspect that the negotiated private royalty rates in our sample are meaningfully lower, if at all, compared to federal royalty rates.

Additional anecdotal information on private land contracts in the checkerboard in Lewis (2015) raise some concerns about whether the standard contracts written on private land were the norm in the checkerboard. In particular, one primary private landowner in the checkerboard, the Union Pacific Railroad, may have changed its contracting approach from standard long-term contracting with firms Champlain and Amoco/BP to selling outright its mineral rights to a firm that also engages in extraction, Anadarko. One potential outcome of this change would be an effective reduction in the royalty rate on private land if Anadarko chose to drill its own wells. Overall on the checkerboard, Anadarko operates about 16 percent of all wells and, as Lewis (2015) suggests, any change in their contract structure will have important implications in measured outcomes. In the Mesaverde sample, however, Anadarko operates only 0.22 percent of the wells and is thus unlikely to meaningfully impact our cost estimate.

5.4.2. *Restricted Leasing*

Our analysis implicitly assumes there are no constraints on which sections are available for production. However, federal land may be more likely to be withheld from the leasing process. For instance, the BLM does not allow oil and gas leasing on federal lands that are designated as wilderness areas (Kornze, 2016). Such restrictions on leasing would provide a plausible explanation for lower oil and gas production on federal land.

Based on discussions with BLM field offices, we are not aware of federal lease withholdings within the checkerboard during our sample period. Furthermore, federal lease withholdings typically have minimum area requirements that are precluded by the square-mile resolution of the railroad checkerboard. For instance, removing an area from federal leasing to protect sage grouse habitat requires at least eleven square miles of contiguous federal ownership (BLM, 2010). Such contiguous areas do not exist in our sample, and therefore we are confident federal leasing restrictions are not an important driver of our results.

5.4.3. *Bonding Requirements*

Bonding requirements for site reclamation can also differ across ownership types and can affect oil and gas extraction decisions for some firms, as they may erode liability protection provided by bankruptcy laws. For instance, higher bonding requirements in Texas caused small firms to exit the market and improved environmental performance (Boomhower, 2019). Although Wyoming sets bonding amounts for state and private land, federal law provides for lower minimum bond amounts and a less complex system for calculating and providing compensation on federal land (Kulander, 2009). Therefore, differences in bonding requirements, if anything, favor drilling on federal land and would lead to lower federal cost estimates all else equal.

6. Public Benefits of Federal Ownership

The checkerboard setting is less well-suited for estimating the benefits of federal ownership. Many potential benefits—such as reductions in air emissions or surface water contamination—are spatially diffuse and therefore do not respect section boundaries. Moreover, to the extent that federal ownership affects well-level outcomes such as operational safety, the set of wells observed on adjacent federal and private parcels will itself be endogenously affected by treatment, complicating interpretation. In this section, we briefly discuss the benefits of federal ownership, particularly as they relate to environmental regulations.

6.1. Habitat Protection

Less drilling means less land disturbance, so it is likely federal ownership has led to less disturbance of habitat. However, because environmental damages from oil and gas operations vary by location, the welfare effects of regulation depend not only on how much activity is reduced, but also where reductions occur. BLM RMPs determine where leasing and development are allowed and establish protective designations, stipulations, and management prescriptions for sensitive habitats.

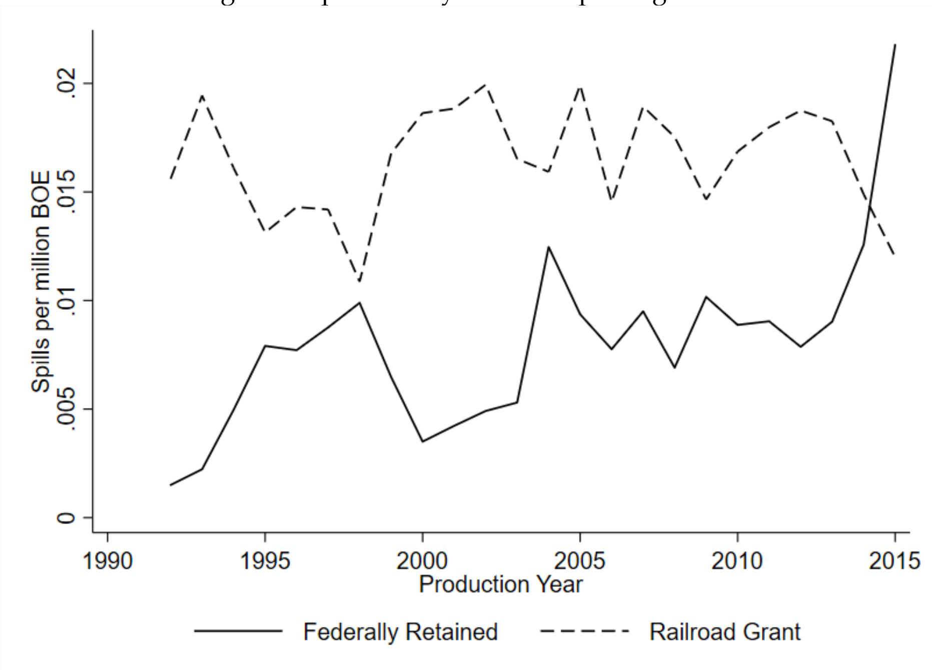
Even though protective designations that preclude oil and gas leasing from an area do not occur in our sample, spatially-explicit lease stipulations that correspond to marginal environmental damages, such as targeted protections tied to sensitive species habitat, can achieve a similar effect of deterring oil and gas activity from high conservation value areas. Indeed, in section 5.2, we present suggestive evidence that operators may especially avoid sensitive ecological areas on federal lands. We note, however, when added costs are not tied to spatially-explicit environmental goals, such as those that arise from permitting backlogs, we do not expect as large an environmental benefit per unit reduction in oil and gas activity.

6.2. Spills and Reclamation

After the permitting phase, operations on federal land also undergo additional environmental and safety inspections overseen by the BLM, which may reduce accidents such as spills. However, inspections are not guaranteed and depend on the capacity of the relevant field office. A report by the U.S. Government Accountability Office (U.S. Government Accountability Office, 2005) found that the rise of permitting backlogs eroded the agency's ability to conduct inspections and implement environmental mitigation activities. According to the report, many field offices only achieved a fraction of their inspection goals because of the resources devoted to processing drilling permits.

We examine data on spills from the WOGCC (1992-2015) and find that there tend to be fewer spills on federal land relative to private land over the sample period, even after accounting for differences in production (see data appendix A.1 for details). Over the sample period, the spill rate on federal land is half the rate on private land. However, as shown in Figure 8 the federal-private difference erodes over time, as the federal spill rate generally increases while the private spill rate is relatively steady. This trend coincides with rising permitting delays and is consistent with a reallocation of effort within BLM field offices toward permit processing and away from inspection duties as described in the GAO report.

Figure 8: Spill Rate by Ownership Assignment



Notes: Plots of WOGCC spill data over time by assigned ownership from 1992-2015 for the Wyoming checkerboard. Spills are normalized per barrel of oil equivalent produced.

We also have reason to suspect worse environmental performance on federal lands with respect to site reclamation. When a well no longer produces, it still has the potential to contaminate water supplies, degrade ecosystems, and emit methane and other air pollutants. Operators are responsible for site cleanup and plugging wells before abandoning them. As noted in section 5.4.3, and in contrast to the permitting process, bonding requirements have historically been weaker on federal land than on state and private land. If operators go bankrupt, their wells become "orphaned," and plugging and reclamation falls to the federal or state governments for wells on federal or private land, respectively. Lower bonding requirements imply the federal government is more likely to lack sufficient funds for these liabilities, which can lead to more orphaned wells on federal land.[22]

6.3. Pollution

We do not attempt to measure the effects of federal ownership on local air and water quality. However, with the possible exception of orphaned wells, it is reasonable to assume that federal ownership has led to a relative reduction in localized pollution levels by imposing more stringent pollution rules and reducing oil and gas activity overall.

In contrast, the effect of federal ownership on global greenhouse gas emissions is less clear. The additional cost of operating on federal land reduces domestic fossil fuel production and therefore the total global supply of energy. However, this reduction will be partially offset by increases in substitutes supplied from other global producers. Because U.S. oil and gas resources are relatively high in natural gas content, which is less carbon-intensive than coal or oil, a decrease in domestic production may lead to a more carbon-intensive global energy mix (Acosta, 2023).

7. Conclusion

We find robust evidence that federal land ownership has substantially deterred drilling activity relative to otherwise comparable private land since the 1990s. Though the benefits of federal ownership are not explicitly quantified in our analysis, the implied economic costs of federal ownership are sizable and appear to be closely linked to bureaucratic process. Consistent with industry accounts, our results indicate that permitting delay, driven largely by agency capacity constraints and procedural complexity, are a central mechanism underlying the higher costs of development on federal land.

While it is tempting to think that bureaucratic delay and its deterrent effect on oil and gas development represent a positive environmental outcome, the general equilibrium effects of reducing domestic energy supply complicate this assessment. Furthermore, our analysis suggests that permitting delay is driven primarily by bureaucratic backlogs rather than by the environmental risks of particular projects. We find no evidence that longer permitting delays are concentrated in environmentally sensitive areas or have predictable spatial patterns, suggesting that these delays are largely systemic rather than site-specific. Blunt tools, such as generalized delay, are unlikely to achieve cost-effective environmental protection.

The speed at which the BLM issues permits for energy and infrastructure projects on the vast domain of federal lands it oversees is a topic of continuing legislative debate (U.S. Senate Committee on Energy and Natural Resources, 2025). Our analysis suggests there is room for changes to the status quo that may offer a potential area of policy compromise between stakeholders concerned with development and environmental protection. For instance, combining simplified permitting procedures or expanded use of streamlined review pathways with additional targeted closures of ecologically sensitive areas, has the potential to increase domestic energy production *and* environmental quality. This change could also lead to additional environmental benefits by redirecting agency resources away from permit processing and toward environmental inspections and compliance. A related policy reform would be to increase BLM personnel, a change that could potentially be financed through permitting fees. As noted in the discussion of the 2005 Energy Policy Act, operators are often willing to pay substantially higher federal fees when they result in a faster, more predictable permitting process.

More broadly, this study illustrates how quasi-experimental variation in natural resource ownership can be used to infer the economic effects of regulatory and administrative institutions even when direct

[22] There are over 4,000 documented orphaned wells in the WOGCC data, yet only 21 occur in our checkerboard sample, 17 of which come from a single operator. Though none of these wells occur on federally assigned land, we are dubious about the usefulness of the observed pattern, as orphaned well documentation is notoriously incomplete throughout the U.S. (Kang, Boutot, McVay, Roberts, Jasechko, Perrone, Wen, Lackey, Raimi, Digiulio, Shonkoff, William Carey, Elliott, Vorhees, and Peltz, 2023).

measures of compliance costs or bureaucratic effort are unavailable. Public bureaucracies exert substantial influence over the allocation of economic resources and are often accountable to multiple constituencies. Balancing these obligations can lead to complex rules and procedures that are poorly aligned with administrative capacity and difficult to remedy. Although federal regulations governing the development of publicly owned natural resources are designed to protect the public's interests by shaping market behavior, the bureaucratic processes developed to implement these protections independently alter this behavior. Our results show that the procedural features of government resource management can generate large and economically meaningful effects on investment and, in some cases, may matter at least as much as the rules they are intended to enforce.

A. Appendix

A.1. Data Appendix

A.1.1. Section boundaries

Section bounaries are taken from a geodatabase of cadastral reference features (CADNSDI) maintained by the BLM. Initial ownership assignment is determined by identifying even and odd-numbered sections of townships withing the Public Land Survey System (PLSS). Data on current land ownership come from two sources. We identify federal subsurface ownership using the 2014 Surface Management Agency (SMA) shapefile from the BLM `http://www.blm.gov/wy/st/en/resources/public_room/gis/datagis/state/state-own.html` and state subsurface ownership from the State Subsurface Ownership shapefile from the Wyoming Office of State Lands and Investments `http://gis.statelands.wyo.gov/osligis/oilandgas`. Subsurface rights that are not federally or state owned are assumed to be privately owned. To be sure, we cross-check our private ownership designation with ownership information from sections with approved drilling permits (r=0.99). In the case of ownership areas smaller than the section, we assign ownership in proportion to area owned by type.

A.1.2. Land Characteristics

Sage grouse habitat measures are calculated at the section level with spatial analyst in ArcGIS using Hanser, Aldridge, Leu, Rowland, Nielsen, and Knick (2011): A raster layer on the probability of high abundance of greater sage-grouse, accessed through: `https://pubs.er.usgs.gov/publication/70118768`.

Subsurface permeability is calculated by intersecting our shapefile of PLSS sections with a shapefile of shale plays created by the Energy Information Administration (`https://www.eia.gov/maps/maps.htm`). Sections intersecting areas of low permeability are assigned a 1 and 0 otherwise.

Elevation and terrain ruggedness measures are calculated at the section level with spatial analyst in ArcGIS using a 90 meter digital elevation model created by the United States Geological Survey. Elevation is the mean elevation reading within a section and terrain ruggedness is the standard deviation.

A.1.3. Well-level Production

Data on monthly "case" level production between January 1978 and August 2019 and wellhead data was downloaded from the WOGCC website. Wells crossing multiple geologic formations can have multiple cases, and our production data sums across all cases at the well level. Months in which wells have no oil or gas production data are assigned a 0. Oil production is reported in barrels and natural gas in MCF. We divide reported natural gas production by 5.8 when measured in barrel of oil equivalent (BOE). Each well in the production data set is merged to its wellhead data (> 99.9% match rate) and then matched to a PLSS section (> 99.9% match rate).

A.1.4. Resource Prices

Oil prices come from a publicly available monthly time series of the Wyoming crude oil first-purchase price, provided by the EIA (`https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F004056__3&f=M`). A weekly time-series of natural gas prices from the Opal Hub were purchased from Natural Gas Intelligence. We average weekly data to create monthly natural gas prices. Natural gas prices are multiplied by 5.8 when production is measured in barrel of oil equivalent (BOE).

A.1.5. Revenue per Section as seen in table 4

We first calculate monthly revenue per well using observed oil and gas production data, multiplied by monthly prices. These amounts are summed over all wells on the section and all months between 1978-2016.

A.1.6. Transportation and Processing Costs

We estimate post-production costs at $3.40 per BOE based on federal sales data (U.S. Department of the Interior, Office of Natural Resources Revenue, 2026) (`https://revenuedata.doi.gov/query-data/?dataType=Federal%20Sales`). To calculate cost per BOE, we sum reported allowances for post-production transportation and processing costs, divided by natural gas production for the state of Wyoming in 2013, the earliest year in which data is available.

A.1.7. Drilling Cost per Foot

Data on drilling costs comes the average drilling cost per foot for natural gas wells provided by the U.S. Energy Information Administration (`https://www.eia.gov/dnav/pet/pet_crd_wellcost_s1_A.htm`).

A.1.8. Calculating expected production (Mesaverde sample)

We employ decline curve analysis to estimate the expected production in each year over the lifetime of a well. We assume a well lifetime of 40 years. Estimates of expected production are based on three years of realized production data and forecasted production thereafter. Forecasted production is based on decline curve analysis that approximates techniques widely used in the oil and gas industry. For simplicity, we parameterize a single decline curve for our sample.

To forecast production we use the cost estimation sample and further restrict it to wells with at least 10 years of production history and with a spud date after 1992.[23] The latter restriction reflects that wells drilled in the Mesaverde reservoir prior to 1992 had a noticeably different energy mix than those drilled after and may have different decline properties. These earlier wells also tended to be a single well per section. As our analysis focuses on the decision to drill multiple wells on a section during a boom in the 2000s, the marginal wells in our analysis that drive our costs estimation almost exclusively come from the period after 1992.[24] Our final sample consists of 1,677 wells.

We relate the initial well production rate to the production rate in year t as

$$q_t = q_o \delta_t$$

where q_o is the initial production rate and δ_t is a decline factor that gets smaller with time. Arps (1945) suggests the following equation for the decline factor

$$\delta_t = \frac{1}{(1 + bDt)^{1/b}}$$

in which D is the initial (instantaneous) rate of decline and b describes the degree of curvature in the decline.

We choose year 2 as the starting point for the decline analysis[25] and use the average production from all wells in our sample for years 2 to 3 to estimate D in the following way

$$D = \frac{1}{b}\left(\left(1 - \frac{\bar{q}_2 - \bar{q}_3}{\bar{q}_2}\right)^{-b} - 1\right)$$

[23]Most of which ($\tilde{8}$5%) are drilled into the Mesaverde reservoir.

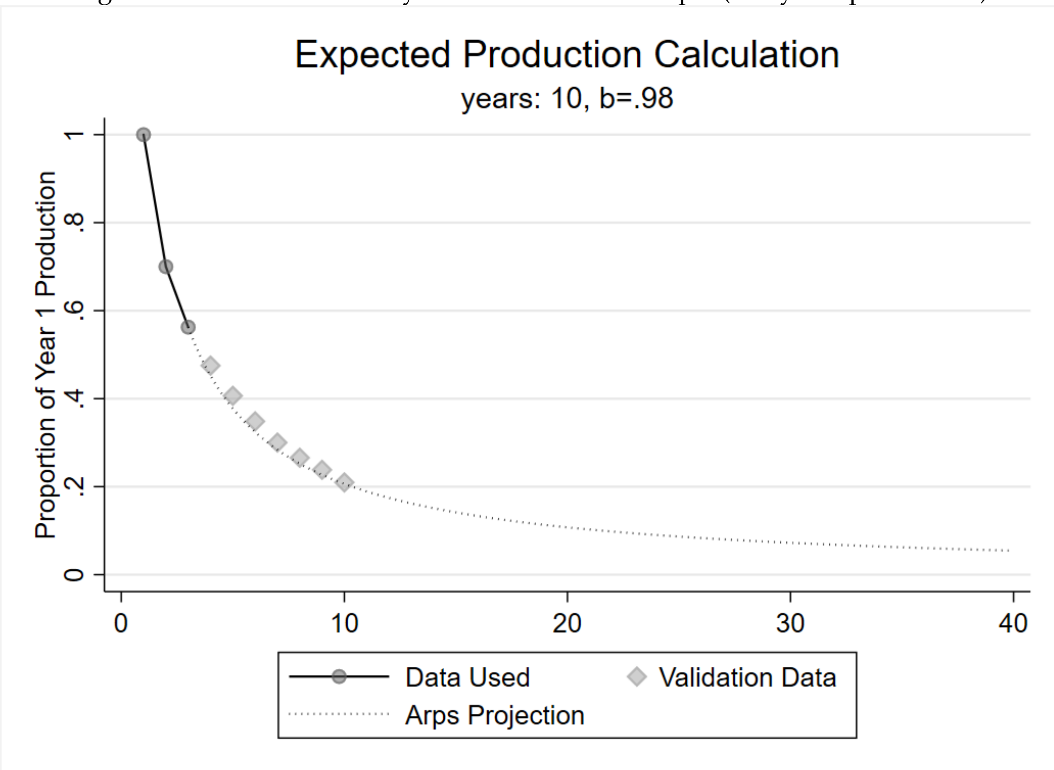
[24]Wells drilled before 1992 are still counted as wells drilled in the final cost estimation, they are just not used in the forecasting stage.

[25]Decline analysis implicitly assumes that the initial production rate is also the peak production rate. Though year 1 is typically the peak year, we observe many examples where production increases from year 1 to year 2.

where $\frac{\bar{q}_2-\bar{q}_3}{\bar{q}_2}$ is the percentage loss in average production rate across all wells from years 2 to 3 and the rest of the expression backs this discrete change to an instantaneous rate. For our sample we find $\frac{\bar{q}_2-\bar{q}_3}{\bar{q}_2} = 0.175$.

We choose the value of b so that the projected quantity matches average production in the 10th year. In this case, b=0.75 and therefore D=.207. The results of this analysis are summarized in Figure 9.

Figure 9: Decline curve analysis for Mesaverde sample (15+ years production)



We then use these parameters to calculate expected production for an representative well in each township. We first caculate $\bar{q}_{i1}, \bar{q}_{i2}$, and $\bar{q}_{i3}$, the average production for wells in township i for each of the first three production years We then calculate the remaining production years using the period-specific decline factor multiplied by $\bar{q}_{i3}$.

A.1.9. Calculating expected present value revenue (Mesaverde sample)

Because we assume expected resource prices and variable costs are constant over time (see below), only expected production and the discount factor change over the lifetime of the well in our expected revenue calculation. Therefore, we can express township expected present value revenues (after subtracting taxes, royalties, and variable costs) in terms of the observed data as:

$$R_i = (1-\tau_I)(1-\tau_R)(P-X)\left(\bar{q}_{i1}\beta + \bar{q}_{i2}\beta^2 + \bar{q}_{i3}\psi(r,D,b)\right)$$

where $\psi(r,D,b) = \sum_{t=3}^{40} \beta^t \delta_{t-3}$ represents the sum of the discount factor times the decline factor across production years.

We calculate the price of a barrel of oil equivalent (BOE) as a weighted average the oil price (15 percent) and natural gas price data purchased from Natural Gas Intelligence (85 percent) to roughly reflect the fraction of energy coming from each fuel type in our sample. The real price per barrel of oil equivalent is set to \$64 averaged over 2005 and 2006. This period represents the peak estimated value of an average well (average net production revenue minus average drilling cost) in the Mesaverde reservoir based on a two-year average. Using prices from a single point in time in our estimation is based on the principle that an undrilled section is not profitable at the time of observation or any time prior.

We estimate variable costs at \$3.40 per BOE based on data from 2013 (the earliest year available), $\tau_I = 0.35$ is the federal income tax rate,[26] $\tau_R = 0.125 + 0.06 + 0.062 = 0.247$ is the sum of the royalty rate plus state/local tax rates. We assume a 10% discount rate.

A.1.10. Calculating expected net present value revenue (Mesaverde Sample)

Expected present value net revenue is defined as expected present value revenue (after royalties and taxes) minus expected drilling costs (after taxes) for the township. The (effective) expected drilling costs are calculated as

$$(1-\tau_I)C_{0i} = (1-\tau_I)c \times \bar{d}_i \tag{10}$$

where $\bar{d}_i$ is the average drilling depth of all producing wells in township i and c is the average cost per drilling foot and τ_I is the federal income tax rate. As with energy prices, we average over 2005 and 2006 and adjust to base year 2015 to get $c = \$370$.

A.1.11. Permit Data

The full history of oil and gas APDs received and approved by the state of Wyoming through 1900-2019 were downloaded from the WOGCC website. We match 98% of permit applications received to the PLSS section level. Multiple permits for the same well are collapsed to the well level using the well's API number. We drop permits with inconsistent dates (for example, permit application date after approval date). When we restrict the sample to the checkerboard area, we are left with applications for 9,300 unique well locations, 9,178 of which are approved, 6,215 of which are drilled.

A.1.12. Sensitive Species

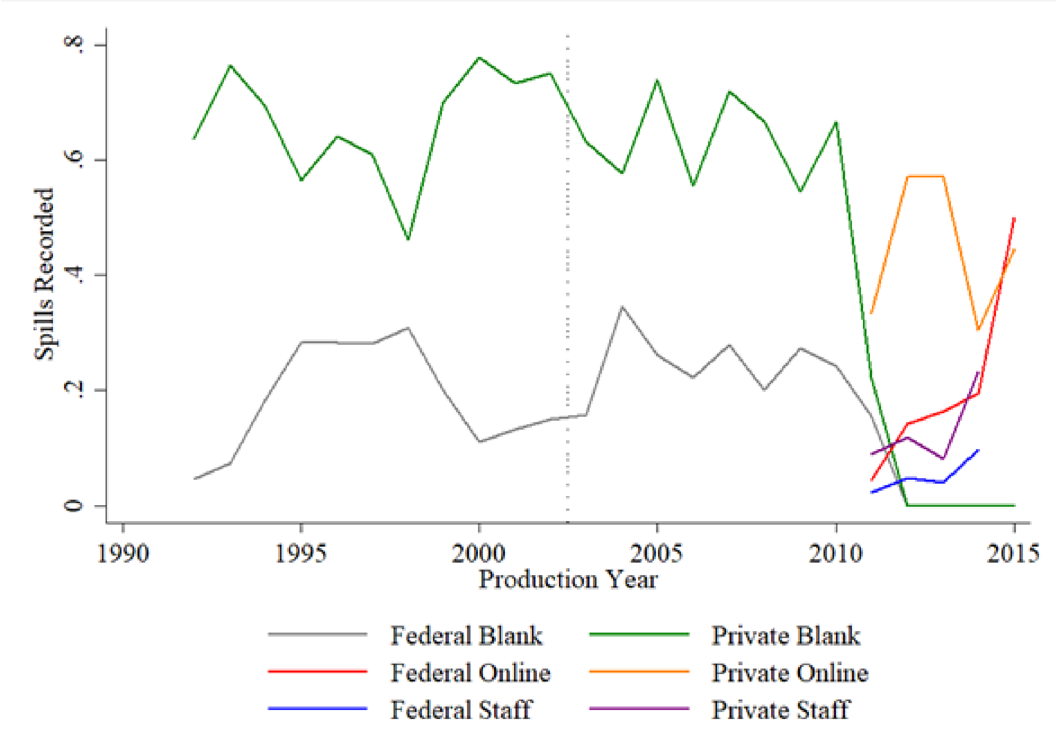
Township-level counts of sensitive species as well as indicators for the presence of the greater sage grouse and endangered species are derived from the Wyoming Natural Diversity Database (https://wyndd.org/species_list).

A.1.13. Spill Data

Data on well spill reports for the years 1992-2015 were also shared by the WOGCC. Producers on all land types are required to report spills at the well site to WOGCC. Since 2015, all reports are submitted electronically via an online portal. Prior to 2015, companies were given the option of filing electronic or paper reports. The data identifies the PLSS section where the spill occurred, the date, and the name of the company, among other information. The WOGCC is responsible for regulating spills that occur at the well, while any spills that occur during transport are regulated by the Wyoming Department of Environmental Quality. Chapter 4 Section 3 of the WOGCC Rules and Regulations requires a written report of all spills "of crude oil, condensate, produced water, or a combination thereof, which occur on a lease, unit, or communitized area" of more than one barrel (42 gallons). Reports must be filed as a written report within 15 working days of the spill. Industry sources indicate that any spill that requires a report is considered a major spill event. Figure 10 shows a breakdown of reports by type, where known, and indicates that trends in reporting between land types generally appear consistent across methods of reporting.

[26]This rate represents the marginal tax rate between 1993 and 2017 on corporate income above \$10,000,000. Over the same period, the marginal tax rate on income between \$335,000 and \$10,000,000 is 34 percent (https://taxfoundation.org/data/all/federal/historical-corporate-tax-rates-brackets)

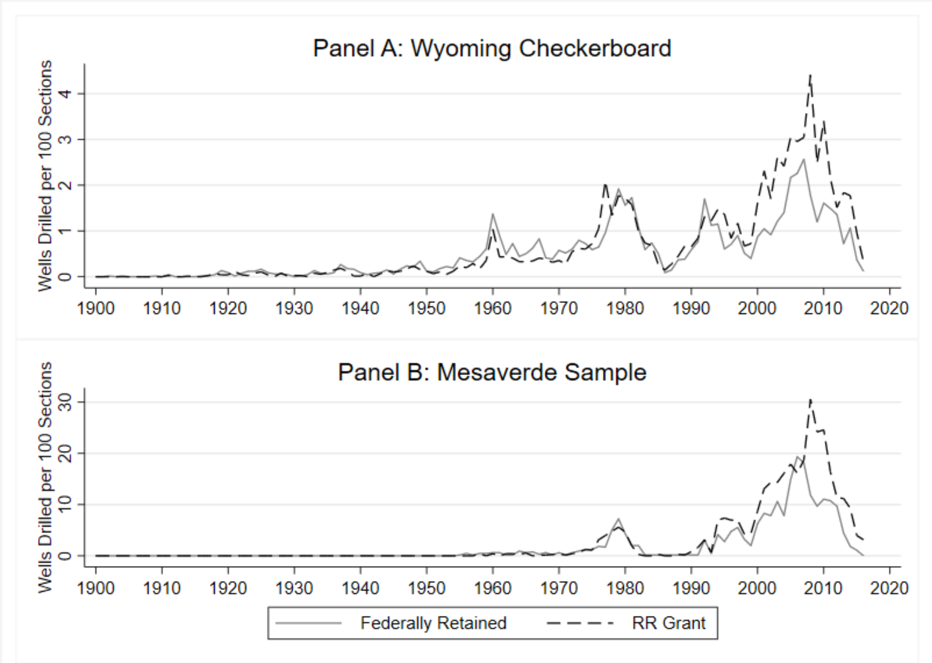
Figure 10: Spill Reports by Categorized Report Type, As Percentage of Total Spills



Notes: Spill reports plotted by year by type of reporting method and initial land ownership allocation. Initially reporting type is not provided, then on some entries "Online" and "Staff" are reported.

A.2. Results Appendix

Figure 11: Drilling Flows by Initial Ownership Assignment



Notes: Panel A plots annual wells spudded per 100 sections based on the initial checkerboard assignment of land ownership and is a companion to table 3 which shows cumulative wells drilled instead of flows. Panel B shows the same measure for the Mesaverde sample.

A.2.1. Mesaverde Subsample

Table 8: Current subsurface ownership by checkerboard assignment (Mesaverde sample)

Mesaverde Sample	Even Sections (Federally Retained)	Odd Sections (RR Grant)
Current Federal	99.85%	-
Current Private	0.15%	100.00%
Current Other	-	-
Sections	651	732

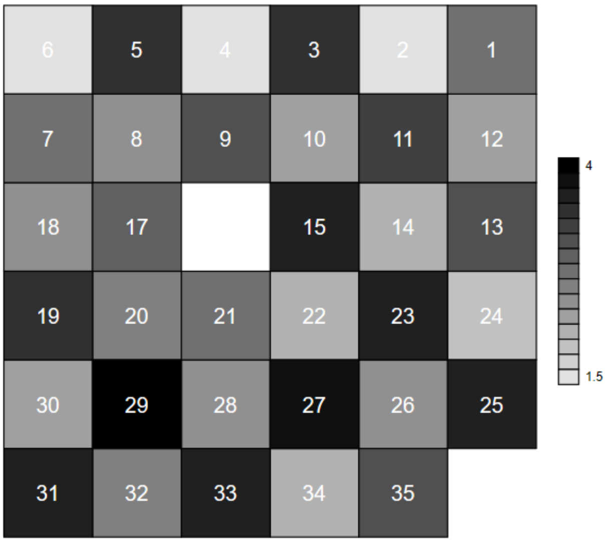
Notes: Percentage of subsurface ownership type in 2018 by even and odd sections for the Mesaverde sample. When sections have more than one subsurface ownership type, ownership is assigned in proportion to area owned by each type within a section. Corresponds to table 1 in the main text.

Table 9: Section characteristics by checkerboard assignment (Mesaverde sample)

Mesaverde Sample	Even Sections	Odd Sections	Difference
Acres	630.84	631.20	-0.36
			[0.30]
Mean elevation (m)	2,104	2,104	-0.22
			[0.39]
Standard deviation of elevation (m)	7.27	7.160	0.11
			[0.18]
Percentage with low permeability surface	100	100	
Percentage with at least 10% sage grouse habitat	100	100	
Percentage in Kemmerer field office	-	-	
Percentage in Rawlins field office	85.89	86.05	-0.16
			[0.35]
Percentage in Rock Springs field office	14.11	13.95	0.16
			[0.35]
Observations	651	732	

Notes: Means and differences by initial ownership assignment for the Mesaverde sample. Robust standard errors for group differences are clustered at the survey township level and reported in brackets. $*** \; p < 0.01, ** \; p < 0.05, * \; p < 0.1$. Corresponds to table 2 in the main text.

Figure 12: Wells Drilled by Section Number (Mesaverde Sample)



Notes: The figure displays average wells drilled per section for each section number in a typical survey township for the Mesaverde sample. Odd-numbered sections are railroad grant lands, and even-numbered sections are lands retained by the federal government. Sections 16 and 36 initially allocated to the state of Wyoming are omitted. This figure corresponds to figure 3 in the main text.

Table 10: Federal Effect on Drilling Investment (Mesaverde sample)

			Mesaverde Sample	
	Cummulative		Even Section Difference	
(1)	(2)	(3)	(4)	
Through 1949	0			
Through 1954	0			
Through 1959	14	1.28**	1.27**	1.33**
		(0.63)	(0.63)	(0.64)
Through 1964	41	2.23**	2.23**	2.28**
		(0.94)	(0.94)	(0.95)
Through 1969	65	3.60***	3.59***	3.65***
		(1.17)	(1.18)	(1.19)
Through 1974	109	4.26**	4.25**	4.31**
		(1.66)	(1.66)	(1.66)
Through 1979	356	2.74	2.73	2.78
		(2.41)	(2.41)	(2.42)
Through 1984	462	4.51**	4.50**	4.55**
		(2.23)	(2.23)	(2.24)
Through 1989	473	4.75**	4.74**	4.79**
		(2.24)	(2.24)	(2.25)
Through 1994	622	-0.52	-0.53	-0.47
		(2.66)	(2.66)	(2.67)
Through 1999	960	-12.16**	-12.17**	-12.11**
		(4.92)	(4.92)	(4.93)
Through 2004	1,714	-37.96***	-37.97***	-37.92***
		(8.55)	(8.55)	(8.56)
Through 2009	2,982	-71.59***	-71.60***	-71.54***
		(21.20)	(21.20)	(21.22)
Through 2014	3,761	-106.62***	-106.63***	-106.57***
		(19.96)	(19.96)	(19.98)
Controls		No	Yes	Yes
Section Acres		No	Yes	Yes
Township Effects		No	No	Yes
Sections		1,383	1,383	1,383
Townships		44	44	44

Notes: Column 1 reports cumulative wells drilled in the sample region through each time period for the Mesaverde sample. Columns 2-4 report coefficient estimates on an even section indicator variable in a regression model of cumulative wells drilled per 100 sections with controls for section size and survey township effects in some specifications. Standard errors are clustered at the survey township level. $*** \ p < 0.01, ** \ p < 0.05, * \ p < 0.1$. Corresponds to table 3 in the main text.

Table 11: Production per Section from Wells Drilled post 1978 (Mesaverde Sample)

	Odd Section Avg. (1)	Even Section Diff. (2)	Adjusted Diff. (3)	Adjusted Diff. (4)
Oil Production (Bbl)	43,065	-12,261***	-12,245***	-12,238***
		(2,750)	(2,784)	(2,805)
Gas Production (BOE)	415,075	-37,327	-37,154	-33,753
		(22,522)	(22,820)	(23,033)
Revenue ($1,000s, Base: 2015)	5,584	-1,101	-1,094	-980.6
		(779.8)	(790.8)	(783.9)
Controls				
Section Acreage		No	Yes	Yes
Survey Township Effects		No	Yes	Yes
O&G Investment prior to 1978		No	No	Yes
Observations (sections)		1,383	1,383	1,383

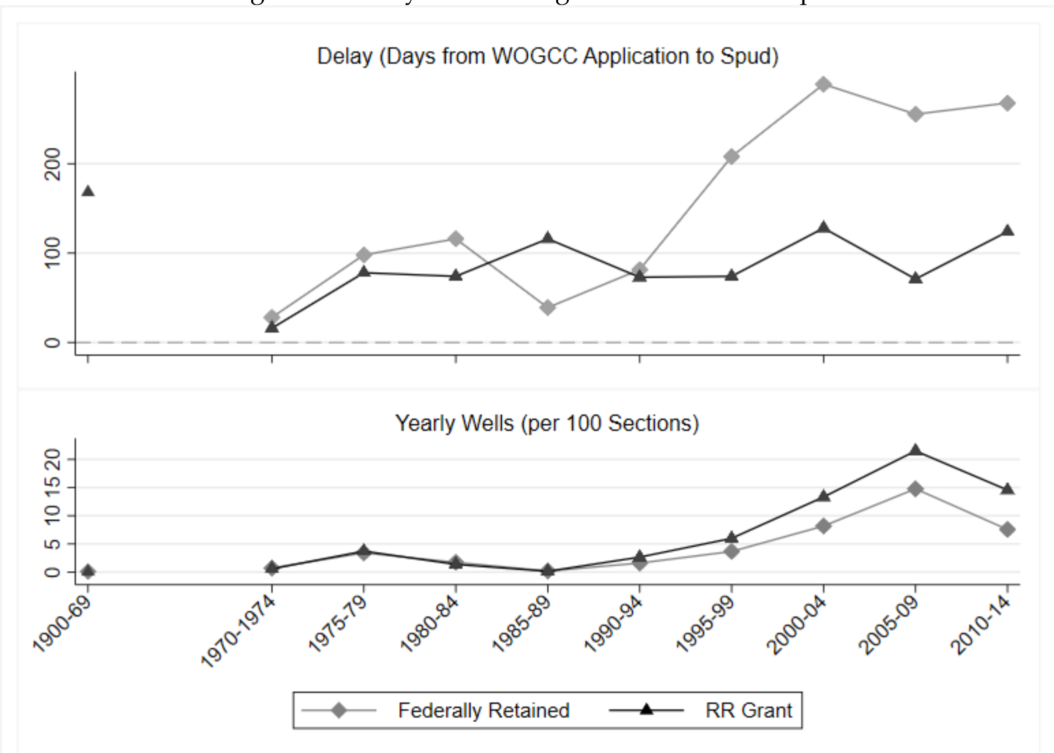
Notes: Reproduces Table 4 for the Mesaverde Sample. Columns 1-2 report means by initial ownership assignment. Columns 3-4 reports the difference associated with even sections with column 4 adjusting for survey township fixed effects. Robust standard errors are clustered at the survey township level and reported in parentheses. *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.

Table 12: Federal Effect on Permitting and Delays (Mesaverde Sample)

	Odd Avg. (4)	Even Diff. (5)	Adjusted Diff. (6)
Proposed wells per section	3.320	-0.235	-0.235
Universe: Sections		(0.166)	(0.168)
Observations		1383	1383
Probability state APD is approved	0.998	-0.00251	-0.00229
Universe: Proposed wells		(0.00237)	(0.00244)
Observations		4438	4438
Days from state appl. to approval	21.25	3.530***	3.034**
Universe: Approved state APDs		(1.190)	(1.190)
Observations		4422	4422
Probability state APD goes to spud	0.894	-0.226***	-0.241***
Universe: Proposed wells		(0.032)	(0.032)
Observations		4438	4438
Days from state appl. to well spud	140.7	175.4***	175.6***
Universe: State APDs going to spud		(10.6)	(10.9)
Observations		3512	3512
Controls			
Survey Township Effects		No	Yes

Notes: The table reports regression slopes for permitting outcomes on an indicator for an even section over the history of oil and gas activity in the Mesaverde sample. Column 3 reports results controlling for township fixed effects. A proposed well is any well plan with at least one APD submitted to the WOGCC. Time between application and approval is top-censored at 730 days. Time between application and well spud is top-censored at 730 days after state approval. Statistical significance using standard errors clusterd at the township level are indicated as *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.

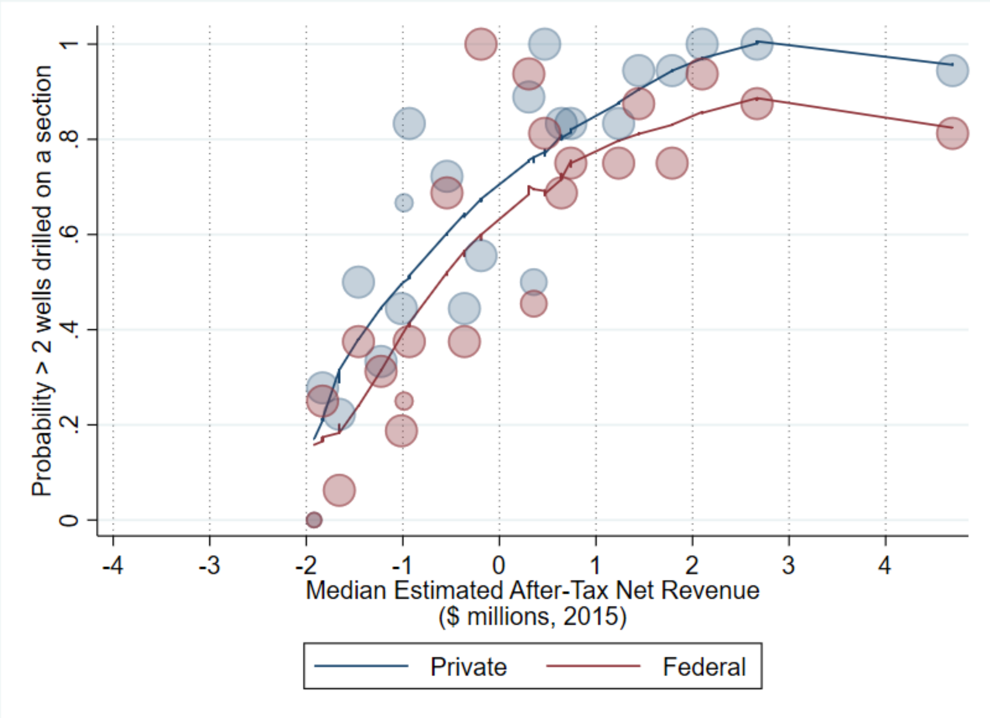
Figure 13: Delay and Drilling on Mesaverde Sample



Notes: The top panel plots the median number of days from WOGCC permit application to well spud for wells in the Mesaverde sample spudded by application date for five-year intervals. The bottom panel plots annual wells drilled in the Mesaverde sample per 100 sections based on the initial checkerboard assignment.

A.2.2. *Back of the Envelope Cost Estimation*

Figure 14: Nonparametric Cost Estimation



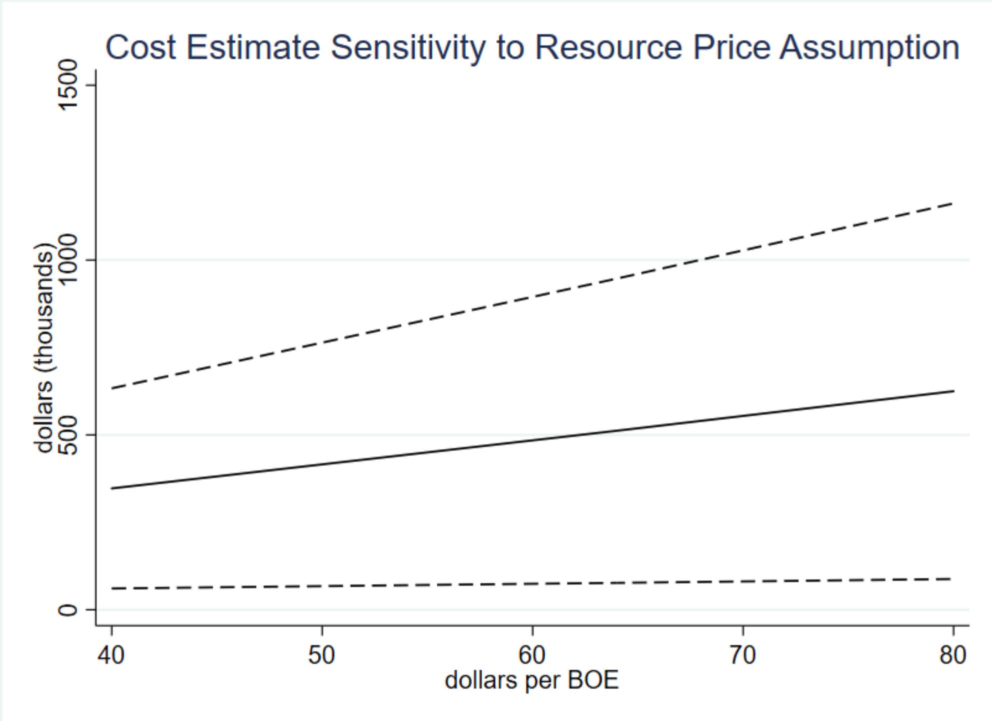
Notes: Solid lines show locally weighted regressions (LOWESS) with Stata's default bandwidth of 0.8 for the probability of drilling two wells over expected net revenue conditional on ownership type overlaid on the underlying township averages.

Table 13: Cost Estimation - Alternate Specifications

	(1)	(2)	(3)
Panel A: Probit Model			
$\hat{\theta}$ (millions, \$2015)	0.587	0.553	0.575
	[0.245]**	[0.265]**	[0.277]**
Panel B: Linear Probability Model			
$\hat{\theta}$ (millions, \$2015)	0.593	0.592	0.620
	[0.274]**	[0.309]*	[0.326]*
Denominator (Median)	Net Revenue	Revenue	Revenue
Geographic Level of Denominator	Township	Township	Township
Control for Median Depth	No	Linear	Quadratic
Sections	686	686	686
Townships	22	22	22

Notes: Replicates the cost estimates from Panel B of Table 5 using a probit (Panel A) and linear probability model (Panel B). The estimation follows the same procedure as in the main text. Robust standard errors are reported in parentheses and standard errors clustered at the township quadrant level are reported in brackets. Monetary values are measured in millions of dollars (base year 2015). Statistical significance is indicated as $*** \ p < 0.01$, $** \ p < 0.05$, $* \ p < 0.1$.

Figure 15: Cost per Well Estimate - Sensitivity Analysis



Notes: The figure plots our estimate of the additional cost per well faced by operators on federal land for different price assumptions for the price per BOE (assumed to be constant over the life of the well). The results correspond to the logistic model estimated using after-tax net revenue at the township level. The dashed lines indicate 95 percent confidence intervals based on robust standard errors clustered at the township level. Monetary amounts are adjusted to a base year of 2015. The cost estimate in the text assumes a price of $64 per BOE, we then multiply it by 0.93 to adjust for using median instead of mean net revenue. Estimates in the figure have not been adjusted.

Declaration of generative AI and AI-assisted technologies in the manuscript preparation process.

Statement: During the preparation of this work, the authors used ChatGPT to prepare drafts of the abstract and highlights section and to improve the readability of a small percentage of technical paragraphs in the manuscript and appendix. After using this service, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

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