ABSTRACT

Title of Document: ESSAYS ON SPLIT ESTATE IN ENERGY DEVELOPMENT

Timothy W. T. Fitzgerald, Ph.D., 2008

Directed By: Professor Kenneth McConnell
Agricultural and Resource Economics

Taking advantage of randomly-assigned federal mineral rights, the first essay establishes the discount that mineral developers place on oil and gas leases with divided ownership. This discount is interpreted as an expectation of reduced profits as a result of transaction costs incurred in obtaining surface access. Results of 53 bimonthy federal oil and gas lease auctions in Wyoming between February 1998 and October 2006 are examined. Bidders discount split estate by 11 to 14 percent on average, but by as much as 24 percent for more expensive leases. Impacts of multiple ownerships and additional leasing stipulations are also explored.

The second essay examines how conflict between surface and subsurface owners affects production from coalbed methane wells in Wyoming. Using well-level production data from 1987-2006, wells on federal minerals with private surface are compared to those on federal minerals with federal surface. A kernel matching estimator is used to control for selection of well sites on the basis of observable information. Delays in entry on split estate are found, but are not associated with reduced production after entry. Some support is found for strategic incentives firms face regarding property rights.

One way coalbed methane production differs from traditional oil and gas extraction is in the large quantities of produced water. Surface discharge has proven to be a low-cost alternative but raises the possibility of externalities. In the third essay a unique dataset linking coalbed methane wells in Wyoming to water disposal permit violations is used to explore differences in environmental performance across severed and unified minerals. A propensity score matching model is used to control for the endogeneity of tenure. The results suggest that split estate wells using surface discharge have a higher number of violations, but the severity of those violations is not significantly different from those on unified estates.

ESSAYS ON SPLIT ESTATE IN ENERGY DEVELOPMENT

By

Timothy W. T. Fitzgerald

Dissertation submitted to the Faculty of the Graduate School of the
University of Maryland, College Park, in partial fulfillment
of the requirements for the degree of
Doctor of Philosophy
2009

Advisory Committee:
Professor Kenneth McConnell, Chair
Professor Erik Lichtenberg
Professor Robert Nelson
Assistant Professor Barrett Kirwan
Assistant Professor Charles Towe

Table of Contents

Table of Contents ii
List of Tables iii
List of Figures v
List of Abbreviations vi
Introduction 1
Essay 1: Evaluating Split Estates in Oil and Gas Leasing 13
1. Introduction 13
2. Oil and Gas Leasing and Development 18
3. Data 25
4. Empirical Framework 28
5. Results and Discussion 32
Tables and Figures 41
Appendix: Results with Log Bid per Acre 49
Essay 2: Estimating the Impact of Split Estates on Coalbed Methane Production 52
1. Introduction 52
2. Comparison of Development Costs across Tenures 57
4. Data 66
6. Results 77
7. Misreporting Results 83
8. Discussion 88
Tables and Figures 90
Appendix 1: Sensitivity Tests for Bandwidth Choice in Matching Results 107
Appendix 2: Matching Results for Misreporting, Bandwidth=0.1 109
Essay 3: The Role of Split Estate in Environmental Performance of Coalbed Methane Development 112
1. Introduction 112
2. Split Estate and Environmental Performance of CBM Wells 116
3. Data 125
4. Empirical Methodology and Results 130
5. Discussion 136
Tables 139
Appendix: Technology of Coalbed Methane 147
Appendix Figures 155
Conclusions 156
Bibliography 160

List of Tables

Introduction

Table 1: Evolution of Homesteading Laws over Time 12

Essay 1: Evaluating Split Estate in Oil and Gas Leasing

Table 1: Descriptive Statistics for Federal Oil and Gas Leases in Wyoming, 1998-2006.. 41
Table 2: Summary of Sample vs. All Lease Sales, 2000-2005.................................. 41
Table 3A: Description and Incidence of Common Lease Stipulations....................... 42
Table 3B: Correlation between Stipulations.. 42
Table 4: One-Way Fixed Effects 43
Table 5: Two-Way Fixed Effects... 43
Table 6: Summary of Point Estimates for Split Estate 44
Table 7: Interaction Models.. 45
Table 8: Categorical Split Estate... 46
Table 9: Quantile Regression... 46
Table 10: Stipulation Results... 47
Table A1: One-Way Fixed Effects 49
Table A2: Two-Way Fixed Effects... 49
Table A3: Interaction Models.. 50
Table A4: Quantile Regression... 50
Table A5: Summary of Point Estimates for Split Estate... 51

Essay 2: Estimating the Impact of Split Estates on Coalbed Methane Production

Table 1A: Summary of Well Observations by Reported Tenure: All of Wyoming ... 90
Table 1B: Summary of Well Observations by Mapped Tenure: All of Wyoming..... 91
Table 2A: Summary of Reported and Mapped Tenure of All CBM Wells in Wyoming 92
Table 2B: Reported vs. Mapped Tenure of All CBM Wells in Wyoming 92
Table 2C: Reported vs. Mapped Tenure of Matchable CBM Wells in NE Wyoming 92
Table 3: Time Paths of Well Reporting 93
Table 4: Observations by Propensity Score Block 94
Table 5: Unbalanced Blocks of Propensity Score with Differences for Primary Variables 95
Table 6: Effect of Reported Split Estate 96
Table 7: Effect of Mapped Split Estate.. 96
Table 8: Regression Results.. 97
Table 9: Regression Results with Propensity Score 97
Table 10: Wyodak Coal Matching Results: Reported 98
Table 11: Wyodak Coal Matching Results: Mapped.. 98

Table 12: Big George Coal Matching Results: Reported 99
Table 13: Big George Coal Matching Results: Mapped.. 99
Table 14: Correct Wells Only.. 100
Table 15: Misreported Wells Only 100
Table 16: Reported Unified Wells 101
Table 17: Reported SE Wells.. 101
Table 18: Mapped Unified Wells.. 102
Table 19: Mapped SE Wells 102
Table 20: Misreporting Regression Results... 103
Table 21: Misreporting Regressions Results with Propensity Score........................ 103
Table A1.1: Reported Tenure, Bandwidth=0.1... 107
Table A1.2: Mapped Tenure, Bandwidth=0.1 108
Table A1.3: Reported Tenure, Bandwidth=0.01... 108
Table A1.4: Mapped Tenure, Bandwidth=0.01 109
Table A2.1: Correct Wells Only 109
Table A2.2: Misreported Wells Only... 110
Table A2.3: Reported Unified Wells 110
Table A2.4: Reported Split Wells.. 110
Table A2.5: Mapped Unified Wells... 111
Table A2.6: Mapped Split Wells 111

Essay 3: The Role of Split Estate in Environmental Performance of Coalbed Methane Development

Table 1: CBM Wells and WYPDES Violations 139
Table 2: WYPDES Permit Violations.. 139
Table 3: WYPDES Permit Violations for CBM Wells Over Time 139
Table 4: Tenure of Wells Matched to WYPDES Permits... 140
Table 5: Ordinal Severity of Violations.. 140
Table 6A: Observations by Propensity Score Block.. 141
Table 6B: Balancing Tests 142
Table 7: Well-Level Matching Results: Kernel Bandwidth 0.035 143
Table 8: Well-Level Matching Results: Kernel Bandwidth 0.1 144
Table 9: Well-Level Matching Results: Kernel Bandwidth 0.01 145
Table 10: Linear Regression Results 146
Table 11: Linear Regression with Propensity Score.. 146

List of Figures

Essay 1: Evaluating Split Estate in Oil and Gas Leasing

Figure 1: Unified and Split Estates, Johnson County, Wyoming……………………48
Figure 2: Percentage Points Bid Discounted for Split Estate by Bid Quantile……..48

Essay 2: Estimating the Impact of Split Estates on Coalbed Methane Production

Figure 1: Map of Sample Wells……………………………………………….…104
Figure 2A: Distribution of Propensity Scores for Reported Split Estate …………..105
Figure 2B: Distribution of Propensity Scores for Mapped Split Estate…………….106

Essay 3: The Role of Split Estate in Environmental Performance of Coalbed Methane Development

Figure A1: Schematic of CBM Well……………………………………………….155

List of Abbreviations

APD: A Permit to Drill; Application for Permit to Drill
Bcf: Billion cubic feet
BLM: Bureau of Land Management
CBM: Coalbed Methane
CSU: Controlled Surface Use
GIS: Geographic Information System
GPS: Geographic Positioning System
Mcf: Thousand cubic feet (standard unit of natural gas)
MMcf: Million cubic feet
NPDES: National Point Discharge Elimination System
NSO: No Surface Occupancy
POD: Plan of Development
SRHA: Stock-Raising Homestead Act
SUA: Surface Use Agreement
TLS: Timing Limitation Stipulation
TTFP: Time to First Production
WOGCC: Wyoming Oil and Gas Conservation Commission
WYDEQ (DEQ): Wyoming Department of Environmental Quality
WYPDES: Wyoming Point Discharge Elimination System

Introduction

Ownership of surface and subsurface rights by separate parties is a common arrangement, especially in the context of energy development. For example, an energy production firm might buy the rights to subsurface minerals from a rancher who retains ownership of the surface for agricultural production.[1] Such a case is commonly known as a "split estate"—in contrast to the more familiar case of a whole tenure, or "unified estate," in which one owner owns both the surface and subsurface rights. Legal scholars refer to the division of surface and subsurface rights as "severance."

Although split estate is implicated as a source of conflict, the effects of severed ownership on the development process are not well-understood. Surface owners who do not also own minerals resist the ability of developers to avoid surface ownership while producers claim that severed minerals are necessary for expanded production. Although the effects of alternative ownership arrangements have been explored in many other contexts, the impacts of divided ownership for energy production have yet to be quantified. This omission is surprising given recent and ongoing policy debate in western states about the effects of split estate. As increasingly diffuse energy resources are exploited due to depletion of traditional reserves and introduction of new extraction technologies, more acres are affected by the development of each unit of energy. Alternative property rights regimes are apt to play an increasingly important role.

[1] Myriad possible alternatives to split estate come to mind: the rancher could lease production rights, sell the whole ranch and lease back the surface, enter various partnerships, and so forth. Split estate is the permanent division of the surface and subsurface "sticks" in the "bundle" of whole tenure.

One expects a single owner to potentially make different decisions than separate but spatially-conjoined agents. Effects of tenure on the tradeoff between surface and subsurface value are both pertinent to the development decision and potentially interesting in other contexts. This dissertation explores the effect that split estate has on three phases of energy development: the value of federal mineral leases on land with private surface as opposed to unified federal ownership; on the production of coalbed methane (CBM) in northeastern Wyoming; and on environmental compliance of CBM wells in Wyoming. This chapter sketches the main issues and outlines the pertinent history of federal split estates.

Locating and producing underground oil and natural gas deposits require specialized human and physical capital. Firms that specialize in the development of resources typically engage subcontractors who specialize in specific aspects of the process, including drilling, servicing, and completing wells. The first observable stage in the development process is the acquisition of acreage on which to prospect. Acquisition can be done in any of several ways, ranging from outright purchase of fee simple tenure to leasing of subsurface or fee simple rights to partnerships with the owner. The focus here is on a comparison between the leasing of split or unified tenures.

After firms identify promising locations to drill, access to the surface is generally needed in order to construct the well. The key difference between split and unified estate is the need to contract with the surface owner over surface access. Surface owners are unlikely to welcome development. Drilling a well and completing the necessary piping to deliver produced oil or gas to market disturbs surface use. During the productive life of a well some portion of the surface is used for activities related to production, for example by housing tank batteries or by allowing maintenance crews to work on the well. At the end of a well's productive life, the site should be reclaimed and the surface returned to its initial condition. However, this is likely to occur decades after development. Coalbed methane wells are less disruptive individually but require large numbers of wells to achieve economies of scale in production. They are also relatively short-lived, with a productive life of 10-20 years.

Surface disturbance during development imposes some anticipated environmental impact in the form of displaced habitat, potential for invasive species, especially weeds, and the possibility of spills. However, there are also systemic effects that result from widespread production. Coalbed methane wells produce water as an essential byproduct—the water must be disposed of in order for production to occur. The quality of this water varies widely, raising concern. In many places the water cannot be reinjected into the ground and must be disposed of on the surface, raising the possibility of contamination of surface water. It is also possible that groundwater might be contaminated by drilling or water disposal. Groundwater mining, groundwater contamination, and increased downstream salinity concentrations are examples of third-party environmental effects from CBM production.

Federal minerals are examined because those tenures are exogenous to the process of developing energy. Private owners are apt to adjust ownerships in such a way as to reflect the value of the underlying minerals—in all likelihood this increases the probability of observing a split estate. The potential endogeneity of severed private minerals to deposits poses an econometric problem. The federal government initially owned all of what became the state of Wyoming, but had land settlement policies throughout the 19th and early 20th centuries to convey land to private individuals.[2] Today laws mandate continued federal ownership of land and minerals, so the government does not have the leeway to adjust its portfolio to reflect the relative values of resources.[3]

Furthermore, with the exception of keystone national parks and the earliest forest reserve withdrawals, the land retained in federal ownership consists of remnants left unclaimed by homesteaders. The national parks and main forest reserves were withdrawn with an eye towards amenity and timber values. For the most part energy development is prohibited in both national parks and original forest reserves, large parts of which are wilderness areas today. So federal land on which energy development occurs was either unclaimed or claimed late in the history of homesteading—later claims are now split estates in which the minerals are retained in federal ownership.

Evolution of homesteading laws supports the assumption that assignment of property rights is not correlated with mineral value. Although the basic legal evolution from the 1862 Homestead Act through the end of homesteading in 1934 has

---

[2] The initial acquisition of land that was to become Wyoming was via the Louisiana Purchase from France in 1803, with the remaining area coming under U.S. government control via annexation of Texas (1845), treaty with Great Britain (1846), and treaty with Mexico (1848).
[3] In the case of lands administered by the Bureau of Land Management (BLM), the pertinent statute is the Federal Lands Policy and Management Act of 1976 (P.L. 94-579).

been related in many places, Gates (1968) remains the definitive source on the legislative history of homesteading and the effects of legal changes.[4]

In order to attract settlers to the western frontier, the federal government allowed each head of household (later adult) to claim up to 160 acres of land. The claimant was then given the option of paying cash or "proving up"—by continuously residing on the tract for five years and improving the property, usually in the form of building a house. Occupancy requirements are specified in greater detail by Gates (1968). An option to purchase the land after a shorter occupancy period was part of the initial Homestead Act and generally maintained in later amendments.

As mineral resources, in particular coal and petroleum, grew in their importance to the national economy, Congress restricted the private claims to the surface rights only. First coal rights were stripped from homestead claims and retained by the federal government via the Coal Lands Acts of 1909 and 1910. By 1916 all mineral resources were withheld, leaving homesteaders with a split estate surface right.

During the first decades of homesteading, the main petroleum and coal-producing regions of the country were in Pennsylvania and Ohio. California and Texas later became leading producing states and geologists then made excursions elsewhere in the West to identify promising locations.[5] Expectations regarding the value of unclaimed land adjusted slowly at first, and then very rapidly as Congress sought to retain ownership of unknown mineral resources.

[4] Nelson (1995) also contains a thorough and concise history.
[5] Yergin (1991) is the definitive history of oil production. McPhee (1986) provides some history of geologic exploration in Wyoming.

As homesteading laws and agricultural practices evolved, presumably the motivations of settlers did not. Homesteaders wanted a parcel of land with good agricultural potential—increasing liberality of land claim laws simply allowed settlers to obtain viable operations. Several economic studies have investigated the decision by homesteaders to claim land. Anderson and Hill (2004) argue that homesteading laws encouraged premature settlement and thus dissipation of some of the rents associated with property ownership. With respect to the homesteading of Wyoming specifically, McFerrin and Wills (2007) argue that in 1890 homesteads in northeastern Wyoming were smaller and more oriented to cereal crops than were homesteads in other parts of the state. They point to this pattern as a proximate cause of the conflicts between large cattlemen and homesteaders.[6] Dennen (1976) discusses the ability of cattleman's associations to exclude others from their range, but also suggests that this deterrent was ineffective against homesteaders. Although some cereal crops persist in the area today, range livestock are the predominant agricultural enterprise, offering support for Anderson and Hill's conjecture that homesteading laws provided incentives for premature claims. Grain farmers prematurely claimed homesteads, which were later consolidated into larger livestock operations.

Libecap and Hansen (2002) conclude that homesteads were too small and too dry for families to survive using received farming practices, and so settlers had to adapt dry-farming practices in order to survive. The prevalence of range livestock operations today suggests that even adapted practices are insufficient in much of Wyoming. Hansen and Libecap (2004) blame lack of information about the true

[6] The armed conflict in the neighborhood of Buffalo in 1892 is commonly known as the Johnson County War. At that time all homesteaders received unified tenure.

aridity of the Great Plains and self-serving political ends for government policy that encouraged the claiming of inefficiently-small homesteads. Many acres were initially claimed but not proved up, thereby reverting to the federal domain.[7]

Table 1 summarizes the major homesteading laws and how the terms under which the federal government granted land to private individuals evolved over time. Two changes typify the progression: the first was a tendency to grant more acreage to each individual in hopes of creating viable farms in the more arid regions of the West; the second was to retain federal ownership of minerals as private individuals claimed larger acreages. Larger acreages were motivated by the late realization that climatic differences across the continent necessitated different efficient scales for agriculture. While the standard 160 acres conveyed under the original Homestead Act was ample to support a family in more humid parts of the Middle West, in more arid regions substantially larger acreage was needed to sustain a viable family farm, let alone a commercial operation.[8] The primary goal of expanded acreage was to convey sufficient acreage to private individuals that subsistence and commercial agricultural operations would be viable.

Until the early 20th century, private citizens received title to minerals along with the surface, which was virtually unprecedented in history before that time (Gruy (2000)) or since. Nelson (1983) has noted the Progressive intentions of the retention

---

[7] The Bankhead-Jones Act of 1934 allowed for purchase of “blown-out” homesteads. For the most part these were marginal agricultural lands. Today B-J lands are administered by BLM. Oddly enough, privately individuals managed to retain mineral rights, so the split estate problem on B-J lands is a “reverse” split estate.

[8] Part of the problem was that the as-yet unsettled West had low agricultural productivity. Thus large acreage was required to create an economically viable operation. “From 88,687 original homesteads [in Wyoming] there came no more than 6,000 farms which is fair evidence that it took 14 original homesteads or 7 final homesteads to make a farm or ranch in this once great cattlemen’s commonwealth.” (Gates (1968)) Later homesteading likely indicates that the surface has lower agricultural potential than previously-claimed land.

of mineral rights. Coal was the main fuel as the United States grew into an industrial power. As homesteaders moved into coal-rich areas of the West, there was concern that coal producers might establish a coal monopoly, perhaps even via fraudulent land claims, with the end result of holding hostage the industrial power of the nation.[9] In the wake of several public lands scandals (notably the Oregon & California (O&C) Lands timber scandal) President Theodore Roosevelt withdrew some 66 million acres of coal lands from entry in 1906. Early the following year he recommended to Congress that the most effective way to deal with this resource would be to enact "such legislation as would provide for title to and development of the surface land as separate and distinct from the right to the underlying mineral fuels in regions where these may occur, and the disposal of these mineral fuels under a leasing system on conditions which would inure to the benefit of the public as a whole" (Swenson (1968)). This vision proved prophetic and federal split estates are the result. Starting with the Coal Lands Act in 1909, Congress withheld the rights to coal underlying lands open to settlement. This created the first split estates in which the federal government retained subsurface rights while homesteaders claimed the surface. Another Coal Lands Act followed in 1910. All mineral interests were retained in federal ownership starting with the Agricultural Lands Act of 1914 as lawmakers recognized the growing importance of petroleum as well as coal. At the time natural gas was not yet an important economic resource, in large part because of transportation constraints. Only decades later were these constraints relaxed.

[9] This concern had earlier given rise to Coal Lands Acts in 1864 and 1873, which provided for purchase of coal-rich lands at prices 8-16 times higher than agricultural land could be claimed under the Homestead Act. See *Amoco v. Southern Ute*, p. 2.

The Stock Raising Homestead Act of 1916 is the most important statute for the conveyance of expanded acreage while retaining federal mineral ownership. It allowed claims of 640 acres (one square mile) but mineral rights did not convey. Nonetheless, it was a hugely popular vehicle for land claims and thousands of claims were made each year from 1916-1934. Western senators had long championed square-mile homesteads (when not pushing for yet larger acreages). The act retained all mineral rights in federal control and was a very important vehicle for land settlement in Wyoming, particularly by dryland farmers.[10]

Since the Stock Raising Homestead Act had created millions of acres of split estate, and millions more with valuable minerals remained unsettled, the federal government had to figure out how to develop its valuable resources. In 1920 Congress passed the Mineral Leasing Act, which provided for the development of federally-owned minerals. McDonald (1979) is the definitive work on the history of the federal mineral leasing program that emerged. This program took shape around the developing legal doctrine of accommodation, which prevents the surface owner from barring the subsurface owner from the overlying surface. Excellent summaries of the finer points of the accommodation doctrine can be found in Davis (2004), Alspach (2002), Mergen (1998).

Focusing on federal minerals reduces concerns about endogeneity. The history of land settlement explains the plausible exogeneity of split and unified tenures with federal minerals. An ideal way to deal with the potential endogeneity

[10] Swenson (1968) states that the first 6 months the law was in place (Dec 1916-Jun 1917) saw 61,909 applications for 23,962,456 acres. However, there was a delay in the processing of applications into 1918 because lands had not been properly classified as eligible for the stock-raising statute. The peak year for processed claims was 1921, when 25,653 filings were made. By that date 105,960,264 acres had been claimed under the Act.

would be to use an instrumental variable for split estate. The agricultural potential of land as assessed circa 1900 would be an excellent determinant of the likelihood that a particular parcel would be claimed and proved up. Assuming the best land was chosen earliest, with less productive land chosen later as mineral claims became more limited, we'd expect to see a negative correlation between agricultural productivity around 1900 and the presence of split estate. It is important to use former agricultural productivity because technological advances, notably widespread development of non-riparian irrigation, may well have changed the rank ordering of various parcels in terms of agricultural productivity today. Libecap and Hansen (2002) highlighted how rank orderings might have changed even during the years when homesteading was still open. There may also be path dependence in terms of the fertility of fields and structure of costs for and agricultural operation. The important thing is that we expect there to be no correlation between agricultural productivity 100 years ago and the productivity of a tract for CBM development today. While this assumption seems tenable, unfortunately no data on historic agricultural productivity is available.

A simpler instrument is the year in which land was homesteaded. This would surely be correlated to the agricultural prospects and uncorrelated with mineral productivity today. However, because earlier homesteads included all mineral rights, we might expect to see private owners adjust their ownership (e.g., by severing the minerals) in reaction to the relative values of the minerals. The effect of this would be to endogenize the tenure to the mineral value, the exact problem we initially seek to avoid. The data exist to use this instrument for federal minerals, but they are scattered in records rooms of county courthouses instead of being collected in a single source.

Table 1: Evolution of Homesteading Laws over Time

Name	Year	Acreage	Requirements	Minerals
Homestead Act	1862	160	5 years residence & improvement	All
Timber Culture Act	1873	160	Cultivate 40 acres trees for 10 years	All
Timber and Stone Act	1878	160	CA, OR, WA: buy @ $2.50/ac	All
Desert Land Act	1877	640	All western states except CO, + ND & SD	All
Kinkaid Act	1904	640	W. NE only, 5 years residency	All
Enlarged Homestead Act	1909	320	Nonirrigable land, later 3 years' residency: "mineral lands" excluded	All
38 Stat. 335 (Agricultural Entry Act)	1914	320	Previous limited patent	Coal reserved
Stock Raising Homestead	1916	640		None

Source: Gates (1968)

Essay 1: Evaluating Split Estates in Oil and Gas Leasing

1. Introduction

Expanded domestic production is a key element of U.S. energy policy. During the past ten years the initial build-out of increased capacity has spawned conflict over the impacts of development of oil and gas. This conflict has been especially bitter on lands where mineral and surface rights are owned separately—a legal condition known as split estate. The economic implications of such ownerships are complex. Gains from specialization afforded by separate ownership may be offset by substantial transactions costs resulting from the necessity of access. Those costs include at a minimum the direct costs of contracting, but may extend to variation in production paths and environmental impacts. Net gains from specialization after these transactions costs are taken into account form the basis for differences in value across tenures. Efficient resource use requires a better understanding of how the institutional environment affects the value of resources. This paper investigates the empirical difference in the value of federal mineral leases on split and unified ownership.

Using data from the initial acquisition of federal oil and gas leases in Wyoming, this paper demonstrates that producers pay less for leases on split estate. Split and unified estates are intermingled throughout the state, effectively offering developers a choice of tenures via which to access comparable reserves. Leasing terms encourage firms to produce oil and or natural gas and pay royalties to the federal Treasury regardless of the surface tenure, so there is little reason to expect significantly different levels of specialization across leases. Therefore the results are interpreted as evidence of some combination of higher contracting costs, lower present value of production (either through less or later production, or both), or more costly environmental performance standards on split estate. This assessment is only from developers' point of view; the values of surface owners are excluded from this study.

Two valuable conclusions result from understanding how alternative ownership arrangements affect the value of resources. First, this provides evidence of split estate affecting the value of energy development, and therefore of federal onshore energy deposits. Second, these results offer quantitative evidence to the ongoing debate over split estates in particular and energy development more generally.[11] Payments for split estate leases are discounted by 11 to 14 percent as compared to their unified counterparts. The discount increases in magnitude for more expensive leases, reaching 24 percent for leases costing $32,240. The discount is reduced when operators have a lease with multiple tenures, providing an opportunity to avoid split estate. Restrictions on lease use are also discounted. Stipulations prohibiting surface use reduce payments 30 to 40 percent, while less stringent surface use restrictions cause a 10 percent reduction in payment. Temporary closures have no significant impact on payments for leases.

These conclusions also help unite two disparate literatures. The first pertains to the value of federal minerals (Boskin et al. (1985)), as well as the leasing of those

[11] Wyoming, Colorado, and New Mexico, three states with substantial natural gas reserves and federal ownership, have all recently passed legislation that addresses the obligations of mineral developers to surface owners in cases where there is a split estate (Wyoming Surface Owner Accommodation Act of 2005 (W.S. 30-5-401); New Mexico Surface Owner's Protection Act of 2007 (N.M.S.A. 70-12); Colorado Surface Owner Protection Act of 2007 (C.S. 34-60-127)). Similar legislation has been considered in other energy-producing states: Montana, North Dakota, and Utah. The impetus for reform in all states has been widespread sentiment that historic provisions protecting the surface owner are insufficient in the face of expanded drilling programs employing new technologies.

resources (McDonald (1979)). The federal government owns substantial oil and gas reserves that are leased to private developers; about 57 million acres of federal minerals are overlain by private surface.[12] Much of the literature on federal mineral leasing focuses on the outer continental shelf for offshore oil and gas development (Hendricks and Porter (1988), Moody and Kruvant (1990), Porter (1995)). A related literature explores auctions for other federally-owned natural resources, most notably timber (Baldwin et al. 1997), Athey and Levin (2001), Haile (2001)).

A second literature has explored the effects of property rights on oil and gas development. Libecap and Smith (2002) document the history of property rights for petroleum. Because oil and gas is migratory and ownership is established by the rule of capture, extraction poses a commons problem as each producer races to extract as much as possible as quickly as practicable. The geophysics of extraction under these circumstances lead to suboptimal resource use as some resource is trapped underground. The traditional solution to the commons problem has been to unitize ownership, sometimes voluntarily but more often compulsorily. Wiggins and Libecap (1985) point out that asymmetric information among firms may cause unitization negotiations to break down, while Libecap and Wiggins (1985) suggest that this breakdown may also limit regulatory remedies. As less permeable formations are being developed now, the commonality of resources is reduced.

Huffman (1982) is the only work on the economics of split estate, but pertains to surface mining (such as for coal) as opposed to extraction from the subsurface (as for oil and gas). While concluding that split estate must be efficient, this work lacks any empirical dimension. Kunce, Gerking, and Morgan (2002) examined cost

[12] Public Land Statistics, 2007.

differences for natural gas wells on federal versus private land in southern Wyoming. Taking advantage of an unusual checkerboard pattern of landholding, the authors concluded that private wells were much cheaper to construct. Because ownership was established long before the gas resources were discovered, the property rights are treated as an experimental design. Although later work invalidated the results (Gerking and Morgan (2007)), the identification strategy is valid. Figure 1 shows how split and unified estate are interspersed in a similar, if less regular, fashion to the checkerboard of alternating unified federal and private tenures. Severed tenures are a result of homesteading policies while the checkerboard is a result of railroad land grants: in both cases the pattern of tenure is determined by factors unassociated with the amount of resource in the ground.

Leases of federal split estate are examined for three reasons. First, the federal government has not adjusted its mineral holdings as private owners do when the relative values of minerals change, which reduces concerns about endogeneity of tenure to mineral value. Second, split and unified estates are intermingled in a patchwork pattern. Homesteaders often leapfrogged, leaving areas unclaimed that today are retained in unified federal ownership. Third, it is crucial to compare tenures which are governed by the same regulations. State- and federal-level regulations apply to numerous facets of the development process, from permitting processes to environmental standards. Regulations follow the minerals, so a comparison between, say, a private surface with federal minerals and a private unified tenure is confounded since the regulations are different. If tighter environmental regulations for federal minerals are more expensive for firms to comply with, then we expect to see spurious negative correlation between split estate and firms' willingness to pay for access to minerals. Mineral acreage is leased under identical rules whether the government owns both the surface and the minerals or the minerals alone. Federal minerals share the same environmental regulations; therefore comparing private to federal surface more closely isolates the economic effects of divided ownership.

Separate maximization raises the possibility of reciprocal costs between surface and subsurface interests. The loss of crop or pasture land to well pads, roads, tank batteries, or compressor plants disrupts surface use, but limiting these impacts comes at the cost of more expensive drilling techniques, less or delayed access, and higher transport costs. Subsurface interests have historically been protected by the legal doctrines assigning property rights to oil and gas developers. Such statutes, known in Wyoming as the accommodation doctrine, reduce the exposure of developers to split estate. If, even with these protections, developers still discount split estate, we can conclude that the resulting estimates are a lower bound on the likely impacts of split estate elsewhere.

Energy exploration and production entails large risks. The challenge of locating, producing, and delivering a valuable commodity to market is the major hurdle facing the industry. An additional source of uncertainty on split estate is the extent to which a surface owner may reduce profits (Chouinard and Steinhoffer (2008)). Even where accommodation doctrine statutes apply, firms are loath to take full advantage of the protections they afford. The fact that development typically proceeds first on unified and then on split estate implies that property rights may define an important intensive margin, determining how many wells may be drilled into a particular formation.

The paper is organized into four sections. A review of the pertinent elements of the leasing and development processes provides a framework for understanding differences across tenures. Then the data and empirical framework are introduced in the following two sections. Finally, results of the several empirical tests are presented and discussed.

2. Oil and Gas Leasing and Development

2.1 Leasing

The federal government has been leasing onshore oil and gas rights since 1920. McDonald (1979) renders a history of the leasing program. Onshore leases are distributed and administered at the state level by the Bureau of Land Management (BLM). A federal oil and gas lease conveys the rights to extract oil and/or gas resources. Geology and technology are such that joint production is common, although non-associated deposits of oil and especially natural gas are common in Wyoming. A firm could sublet the rights to one substance or the other, but in practice this is uncommon.[13] Resources that are leased range from proven reserves to highly speculative or "wildcat" prospects. In contrast to offshore leases, no information about likely deposits in provided in the sale prospectus, so firms must do their own

[13] It is true that some firms specialize in particular types of production, which raises questions of firm heterogeneity addressed below. Forming partnerships across specializations is more common than explicit subletting.

research. Because entry is not allowed unless a tract is leased, some firms lease tracts in order to discover what deposits may underlie it (usually by seismic survey).

The leasing process is started when a tract is nominated for leasing by the public, which may include an interested bidder.[14] The state BLM office processes nominations into tracts that are offered at bimonthly auctions. The tract creation process is opaque, but anecdotally the BLM simply checks to determine if the minerals are already leased, and may include or exclude other nearby parcels in a tract. Tracts are advertised in advance and firms are allowed to submit sealed bids, though most interested bidders prefer to send a representative to the lease sale.

The auction format is first-price open-outcry ascending bid (English). All parcels are subject to a reserve price of $2/acre. Bidding is conducted on the payment per acre, and the total payment made by the highest bidder is the winning bid times the acreage. This initial payment is known as the bonus payment, in contrast to subsequent royalty payments that depend on the amount of production from the lease. Additional administrative fees are applicable on each lease.[15] A noncompetitive mechanism exists for tracts that fail to attract a bid of at least $2/acre at the sale (although a bid of $2/acre must be made in order to acquire them later). About 19% of all leases are acquired noncompetitively, but since only two noncompetitive leases appear in the sample, those observations are dropped and only competitive leases are considered here.

---

[14] This has an important implication for the auction environment. The very fact that a tract has been nominated implies that at least one potential bidder thinks it will be valuable. Moody and Kruvant (1990) discuss the (similar) nomination process for OCS leases: "The very fact that a tract has been offered signals that it was nominated, hence at least one firm thinks that it is worth bidding for. *n.* This effect is mitigated by the common practice of nominating 'scenery' tracts of no interest to conceal the nominator's true intention." (30-1).

[15] In 2005, these fees rose from $75/lease to $130/lease.

Mineral leasing is often cited as the archetypical case of a common-value auction, in which all bidders share the same underlying value for the good. This value depends on how much oil or gas is located under the tract and how much it will cost to extract. A common-value environment gives the incentive to understate the estimate of value in a bid in order to avoid the "winner's curse," or overpayment for a tract relative to the expectations of all bidders. One of the first references to this phenomenon was in offshore oil and gas leasing (Capen, Clapp, Campbell (1971)). The quantity and quality of hydrocarbons is a crucial factor in determining bids, but the auction environment is somewhat more complicated than the textbook common value case.

First, there may be dependent values between parcels. This could be a result of inefficient tract construction or the leasing of neighborhood blocks at different times. A bidder may be interested in obtaining a certain number of tracts in a particular sale—enough to ensure a steady stream of projects but not so many as to require a drastic change in input levels. Production technology or physical relationships between tracts may make certain combinations attractive. Hendricks and Porter (1988) found significant information rents associated with neighboring tracts. The data used here do not support investigating the existence of neighborhood rents, but the possibility of firm-specific values suggests that a private value model for the auction would be more appropriate.

Firms may differ in other systematic ways that affect valuations and therefore bids. Information from previous experience in the neighborhood, possible production spillovers (such as excess pipeline capacity), or firm-specific productivities of the sort explored by Kellogg (2007) are all possible sources of firm-specific heterogeneity. Expected costs may differ across firms; Adelman (1992) suggests that firms can more easily assess cost risks as opposed to geologic risks, and so differences in expected profits likely reflect cost differences.

Resale is a common occurrence, with as many as 60 percent of leases changing hands after the initial auction.[16] Opportunities for resale tend to inject a common-value element into the auction environment. Haile (2001) suggests that resale in timber auctions, where cost differences determine firms' valuations, are best modeled with a hybrid private- and common-value auction setting.

The terms of federal leases are quite uniform. If the BLM wishes to deviate from the standard lease terms, additional use stipulations can be imposed, but are stated for each tract in the sale prospectus. Such restrictions are explored further below. Once a tract is leased, the firm has ten years to produce either oil or gas from it—otherwise the lease reverts to the government. So long as production continues, the firm retains the lease. By maintaining production, it is not uncommon for firms to retain leases for decades. All production is subject to a pre-specified royalty payment. Over 99 percent of the sample leases retain a one-eighth (12.5%) interest; the developer must pay the government one-eighth of the value of the extracted product.

Restrictions on the use of a tract are apt to be an important determinant of lease value. Three main categories of stipulations are examined here. The most restrictive is No Surface Occupancy (NSO). This stipulation prevents surface access in order to protect surface values. Preventing surface access outright is even worse

[16] Sue Moberly, Wyoming BLM, personal communication with author, December 1, 2006.

for the developer that split estate, on which surface access can (usually) be negotiated. Reserves can be extracted by a more expensive technique such as directional drilling, or in the case of sufficient subsurface transmissivity, reserves may migrate to nearby wells. That is, neighboring wells could drain the area under a lease with a NSO stipulation. A weaker version of the NSO stipulation is Controlled Surface Use (CSU). This prevents certain forms of surface use that may affect specific surface values. The weakest type of stipulation is a Timing Limitation Stipulation (TLS), which disallows surface access during particular times of year. These stipulations are commonly used to protect sensitive wildlife habitat (e.g., nesting, parturition, or winter range). Temporary closures are in effect from 60 to 199 days per year (2 to 6-1/2 months). It is possible that multiple TLSs affect a single lease, with potentially overlapping closures. Stipulations are inherently idiosyncratic as their intent is to address lease-specific concerns not covered by standard leasing rules. Stipulations convey information to bidders about likely increased costs on a lease.

2.2 Development

After acquiring a lease, professional geologists analyze the deposits develop a plan for extraction. In many cases deposits are not rich enough to warrant immediate development.[17] If the developer elects to proceed with development, the first step is to submit a plan of development (POD) to the local BLM field office. The plan

[17] This phenomenon is an example of the recent debate over “undeveloped acreage” on oil and gas leases. Firms may develop a single well to maintain control of a lease or simply wait until expiration is imminent to reassess the deposits and market conditions. For a more complete discussion, see GAO (2008).

details wells, roads, pipelines, and other infrastructure. Environmental concerns are addressed and an approximate timeline of development is outlined. Approval is contingent on meeting regulations, including leasing stipulations.[18] In general, the BLM will not offer a parcel unless it anticipates approving some drilling plan, so a thorough POD is likely to be approved. Concurrent with the POD process, a developer must also receive a drilling permit (APD) for each well from the state oil and gas commission. This is also a straightforward process, with very few (1% of all coalbed methane wells) applications denied. Engineering criteria such as well spacing are a primary concern of the state agency. In short, after leasing but before development, the developer is not subject to regulatory holdup by the BLM or the state. Rules apply equally to split and unified tenures.

The most obvious difference across tenures is that an operator must obtain surface access on a split estate lease. This contracting imposes an additional cost not incurred on unified estate. A negotiated agreement for access is known as a surface-use agreement (SUA) and stipulates when, where, and how the operator will occupy the surface. Surface owners are affected by construction of well pads, roads, pipelines, and power lines. In some cases these improvements may be beneficial to the landowner by enhancing real estate value, but typically surface use is diminished. Amenity uses have gained importance in recent years—energy development potentially negatively affects air and water quality, wildlife habitat, viewsheds, and privacy of surface owners. A surface owner who welcomes development without owning the underlying minerals is atypical; a more common reaction is to try to capture some of the resource rents in exchange for access.

[18] The primary pertinent regulations are Onshore Order No. 1, commonly known as the "Gold Book."

In most energy-producing states (including Wyoming), the accommodation doctrine prevents holdup by the surface owner by giving operators an option to enter the surface without a negotiated agreement. If a voluntary contract is not signed, the developer can "bond on" by posting an additional performance bond with the BLM.[19] The size of the bonds is modest—typically $2000, with the burden on the surface owner to increase coverage—and the bond only covers damages to crops or structures, leaving native grass hay or pasture that livestock producers depend upon uncovered. Bonds are seldom used.[20] Signed agreements are the norm. The outside option of the operator is the present value interest cost of a bond adjusted by the probability of default. Accordingly, surface owners are often offered less than they would like for the use of their property, but have an alternative of receiving nothing. The time and money cost of negotiating and signing a SUA or bonding on is unique to split estate, and poses an increased cost.

With permits and surface access in hand, the operator can begin construction of a well. If property rights are uncorrelated with geologic formations, physical construction costs should not differ. On average, depth, hardness, distance, and other physical factors will be equal.

Operators bear substantial costs even after a well is drilled and completed (provides access from a paying formation to market). These costs, elsewhere called lifting costs, include water pumping, injection, and disposal costs. Once a well

[19] Firms are also required to post performance bonds for any operation on federal minerals. Wells may be bonded individually, but many firms opt for blanket coverage at either the state or federal level. The additional bonds, known as Section 3814 bonds, are required only in cases when an agreement cannot be reached with a surface owner on split estate.
[20] Before March 2008 bonds were posted in 55 cases; 10 have been returned after an agreement was reached and 1 remained in place. In March 2008 88 3814 bonds were posted to cover wells on one owner's property in Campbell County.

reaches the end of its productive life it must be plugged and the site reclaimed. It is unclear how these operational costs are correlated with tenures, but to the extent that they are, differences are confounded with differences in contracting costs.

3. Data

Results from 53 federal onshore oil and gas auctions in Wyoming during the years 1998 to 2006 were provided by the BLM. The basic observation is the lease parcel—the physical location of the lease, the amount of the winning bid, and the identity of the winning bidder are observed. Leases from those years have been mapped electronically so tenures can be evaluated.[21] Table 1 contains descriptive statistics for those leases in the sample. Leases range in size from only a few acres to four square miles (2560 acres). Bids are clustered at the minimum acceptable offer—$2 per acre—but range as high as thousands of dollars per acre. The bonus payment, or the total price of a lease to a prospective developer, also covers a broad range. The total bonus payment made is typically the winning auction bid multiplied by the nearest (larger) whole number of acres in the tract.[22]

In order to examine the property rights, ArcGIS was used to overlay digitized versions of BLM plat maps on the leases. Using this data limits the sample since

[21] The full sample includes just over 6.5 million acres in 7337 leased parcels; the total bonus payments made on these leases amounted to $296 million. To judge the completeness of the sample, BLM records show that in the 36 sales during the years 2000-2005, 4.27 million acres were leased in 4681 parcels, yielding $186,897,132 in bonus payments. Over the same time period, the sample includes 4157 parcels covering 3.65 million acres, with a total bonus payment of $ 171,068,691. Table 2 summarizes the coverage of the sample.

[22] Sometimes surveys are amended or leases are split for other administrative reasons, in which case the bonus payment may differ slightly from the offered acreage times the bid. The revised bonus payment will be the bid times the revised acreage. Sue Moberly, Wyoming BLM, personal communication with author, 15 February 2008.

leases made prior to 1998 have not yet been mapped. Some leases are missing, as Table 2 shows and is discussed in footnote 10. Prevalence of split estate is measured on the unit interval, where 1 represents a lease that is entirely split estate. The mapping process proved to be quite accurate and only a fraction of one percent of the sample had to be dropped due to apparent problems.

While it is possible to distinguish between various government agencies that control surface rights, it is not possible to distinguish among different private surface owners. No inference can be drawn from these data on the effects of multiple or single surface owners. Over half of all leases statewide have no split estate to speak of, but one quarter or more exhibit severed ownership. Over half of all leases have a single ownership, but some have multiple tenures. The number of different tenures on a lease is referenced as the number of fragments.

Since BLM does not use split estate as a criteria in constructing lease parcels, it is possible that one or more tenures can be combined in a single lease. For example, a 640-acre lease might be comprised of 320 acres of unified and 320 acres of split estate. The procedure used to map lease tenure causes such a lease to appear as having two fragments. Other leases might have different federal surface agencies (such as BLM and Forest Service) or a lease may (infrequently) be comprised of noncontiguous blocks of land. The lease appears fragmented in these cases as well. It is likely that more fragments reduce the lease value. Empirical tests of this are included below. If there are fewer different ownerships it is more clear what the operator will have to do in order to find and produce minerals.

The lower panel in Table 1 contains descriptive information about the auctions. There is variation in the number of parcels offered in each sale, which in part affects the gross revenue generated. Other variation is explained by the quality of prospects offered and prevailing market conditions, both of which are exogenous. Another issue is whether the auction environment is competitive. Because of the English format, the auction data do not include information about either the number or amount of bids on each parcel, which measure competition for a particular lease. Even the number of bidders who register for each auction is not available to compare competition across sales; we can only observe the number of different winning bidders in each sale and use this measure as a proxy for competitiveness. However, each auction potentially has a different competitive environment due to bidder composition. The number of winning bidders varies from 16 to 73, with an average of 51. Although it is unlikely that every bidder bids on every parcel, this number of participants reflects levels of competition that are adequate to support the interpretation of prices as market valuations. Williams (1990) argues that competitive outcomes arise even with very modest numbers of bargainers or bidders.

Table 2 includes additional information about the sample in relation to all leases. Over the period of the sample leasing activity declined. The most active year in the sample was 1998, which boasts the most (and second-most) tracts (286 in June and 280 in October), the most bonus paid ($14.6m in December), and the most buyers (73 in February).

Data on leasing stipulations were provided by the Wyoming State Office of the BLM. Because the BLM does not categorize stipulations, the pertinent stipulations for each lease were gleaned from the comments on each lease file. Crude measures of stipulations were constructed by creating dummy variables describing each broad category. This gives a coarse view of what conditions pertain to each lease. Table 3A summarizes the incidence of these various types of stipulations. The total number of leases for which stipulations are observed is 7010. Because multiple temporary (TLS) restrictions can affect a single lease, the total number of leases that are affected (4437) is less than the total number of TLS stipulations (6449). However, these multiple stipulations often overlap and sixty percent of leases (2667) have only a single TLS stipulation; the maximum number applying to any single lease is five.

Table 3B shows correlations between the various types of stipulations and split estate. The most restrictive NSO condition is uncorrelated with other stipulations and split estate. While TLS and intermediate CSU stipulations overlap somewhat, both are seen less frequently on split estate than unified. The intuitive reason for this is that BLM uses stipulations to protect other service streams for which it has regulatory authority—for example, wildlife or historic sites. No correlation with fragmentation is observed for any of the stipulations.

4. Empirical Framework

Several variables bear on the observed values of leases. The dependent variable is the natural logarithm of total bonus that firms must pay for a lease; the logarithm accounts for the skewed distribution of bids. The total bonus payment is used for two reasons. First, because oil and gas exploration may be tied to the number of acres available for exploration or drainage, the magnitude of the prospect is captured by the total bonus payment. Second, the bonus payment is the total outlay that firms must make to acquire a lease. Per acre bid is an alternative dependent variable that has been used in other auction contexts, notably for timber auctions. Previous work on oil and gas leasing uses both measures, but total bonus payment is the preferred dependent variable.[23] Results using the logarithm of bid per acre are presented in an appendix.

The most important factor in determining the value of a lease parcel is the quality and extent of reserves. This is not only unobserved by the econometrician, but only observed with possibly significant error by the bidders themselves. Holding other factors constant, increased lease acreage gives a developer a better chance of finding oil or gas. More acres are more valuable. The variable of interest, the percentage of split estate, is presumed to negatively affect prices. Likewise, additional fragments of ownership are assumed to negatively affect bids. The two variables pertaining to property rights, fraction of split estate and number of different ownerships on the lease, are interacted to explore the possibility of second-order effects on bonus payments.

At least three sources of heterogeneity are likely—bidders, regions, and auctions. Bidders might differ in a number of ways: based on whether or not they plan to produce from the lease or have unique cost structures. Prior to leasing and development different bidders may also have very different signals about the value of

[23] Moody and Kruvant (1990) and (1988) are the only two papers on OCS leasing that use bid per acre—all others use the total bonus payment and control for acreage.

oil and gas deposits on a given lease. Differences between firms may change over time and so are accounted for by a random effect.

Leases in different parts of the state are also likely to differ systematically since the underlying resources vary. This similarity is likely to be in terms of both amounts of oil and gas and uncertainty about those amounts. Over time these variables are likely to be constant and are modeled with a fixed effect. An alternative justification is that produced gas is approximately equidistant to marketing hubs, which may affect the net revenues associated with the same amount of resource in different parts of the state.

Finally, there may be systematic differences in bids across auctions, perhaps due to effects either in the auction environment itself or temporal effects that differ between auctions. These concerns about the bidding environment are addressed via a fixed effect.

Indexing tract by *i*, county by *c*, bidder by *j*, and auction by *t*, the basic specification accounts for auction and county fixed effects with a random effect for the bidder.

$$\ln(BONUS_{ijt}) = \beta_1 \%SPLIT_i + \beta_2 FRAGMENTS_i + \beta_3 ACRES_i + \delta_t + \alpha_c + \gamma_j + \varepsilon_{ijt} \qquad (1)$$

The auction-specific fixed effect (δ_t) controls for time-dependent variation that affects all bidders in the same way. Bonus payments will vary with many factors that change over time and affect profits in energy development. For example, input and output prices, expectations, extraction technology, pipeline capacity, and regulations all potentially affect the value of a mineral lease. Although all of these factors might change over time, however they change, they change in the same way for all firms.

Since the geologic characteristics of leases vary across the state, the county-level fixed effect for location (α_c) accounts for systematic differences in the value of leases located in different counties. Super-county regional effects are also possible, but ultimately make little empirical difference.

Including a bidder-specific random effect (γ_j) accounts for systematic variation across bidders. Bidder effects are best accommodated by random effects as they are likely to vary since bidders' relative productivity may change over time. This leaves an error term (ε_{ijt}) that retains any variation across regions and bidders. Clustering standard errors by bidder will account for correlation of bids by a single bidder, but not for correlations in leases won by different bidders. Additional variables of interest, such as interaction terms or variables accounting for leasing stipulations can be added to this specification.

Quantile regressions are used in order to evaluate how impacts of split estate change over the distribution of leases. It may be that split estate is not much of a problem for expensive leases where there are plenty of prospective rents to be shared but that transaction costs take up a larger piece of the pie for wildcat leases. The 25th, 50th (median), and 75th quantiles are used to investigate how marginal effects potentially change across the distribution. Additionally, the 5th and 95th quantiles are estimated in order to understand what happens to the parameters for bids at the reserve price and among very high bids. Quantile regression relies on no distributional assumptions. Standard errors for the estimates are bootstrapped.

5. Results and Discussion

5.1 One- and Two-Way Fixed Effects Results

Working from a reduced form of specification (1), Table 4 provides results of one-way fixed effects specifications for both auction- and county-level fixed effects (columns 1 and 4).[24] Coefficient estimates can be interpreted as percentage changes in payment given a unit change in the explanatory variable; a unit change in split estate is from wholly unified to split tenure. Acreage is a significant positive factor in explaining bids across all specifications, as expected by the construction of the bonus variable. Split estate has a significant and negative effect on the bonus payment, reducing the amount that bidders are willing to offer. The magnitude of the point estimate suggests that holding all other factors constant, if the lease changes from all unified to all split the bonus payment will decrease by about 22% with auction fixed effects and about 15% with county fixed effects. For an average lease, that translates to a difference in bonus of between \$9062 and \$5904 (or \$1987 to \$1355 for a median lease). Fragments have a significant and negative impact on bonus payments with auction fixed effects and no significant impact with county fixed effects.

Auction- and county-level fixed effects specifications with clustered standard errors are also reported (columns 2, 3, 5, 6). As expected, the standard errors are larger in these specifications than in columns 1 and 4, suggesting that there is systematic variation at the auction, county, and bidder levels. As a result of these larger standard errors, split estate is no longer a significant determinant of bonus payments, except in the case presented in Column 6, where county-level fixed effects

[24] Random effects models were run for comparison and rejected in favor of fixed effects. Results are available on request.

are combined with standard errors clustered on bidders. Fragments have no significant impact in these specifications. These results suggest that correlations among bids by the same bidder or in the same county are less important than correlations across bidders and counties. The size of the standard errors suggests that simply accounting for correlations ignores potentially different levels within a county or in bids by one bidder.

Table 5 presents results from two-way (auction and county) fixed effects in Column 1. Though the point estimate for split estate is somewhat smaller than was seen in the one-way models—about 13% or $5286 for the mean lease—it is still significant. Results of a mixed model incorporating both the auction-specific fixed effects and bidder random effects are presented in Column 2 of Table 5. The marginal effect of split estate falls to near 11%. In both specifications the marginal effect of fragments is positive, which was unexpected. This positive value will be discussed further in the following section.

The top panel of Table 6 compares the estimates for split estate across the main specifications. These point estimates steadily decrease from 22% in the auction fixed effect to 11% in the mixed specification. Split estate has a significant and negative impact on bonus payments across specifications, as expected.

5.2 Interaction between Split Estate and Fragments

A parcel that is comprised of a single tenure will have only one fragment. Instead of switching entirely from split to unified, the parcel might also include an additional fragment. Because of the way the GIS data is classified, an additional fragment cannot be another piece of split estate.[25] On a contiguous lease other tenures must be unified. Therefore the bidder knows that some portion of the minerals can be accessed from the unified estate and the surface owner may possibly be avoided. Bidders are willing to pay a premium for the ability to avoid the surface owner. This possibility is explored in a series of regressions reported in Table 7, which include an interaction term for split estate and fragments. Large negative coefficients on the split estate variable are offset by more modest, sometimes positive coefficients on the interaction term. Construction of the variables makes interpretation of the interaction term by itself difficult.[26] However, the marginal effect of split estate in unambiguously negative. The results confirm the value of an alternative tenure on a lease when there is also split estate. Fragments themselves have no effect on the bonus paid, but in the presence of split estate these other (non-split) tenures provide an alternative for firms to access the subsurface.

The lower panel of Table 6 compares across specifications the estimates for split estate including the interaction term. The first column is the reported coefficient for split estate, the second the reported coefficient for the interaction term. The third column reports the marginal effect of split estate through both terms for the median lease.[27] Adding the interaction term increases the magnitude of marginal impact split estate has on bonus payments for most leases, which are not fragmented. This can be seen by comparing the marginal effect in each family of model for the median lease

[25] Unless the parcel is noncontiguous. The effects of non-contiguity are confounded here, which is significant insofar as the expected direction of effect is opposite that argued for added fragments here.
[26] A Wald test for jointness of % SPLIT and FRAGMENTS is rejected for all specifications.
[27] The full marginal effect is: $\beta_{\%SPLIT} + \beta_{\%SPLITxFRAGMENTS} \cdot FRAGMENTS$. The mean number of fragments is 1.29, so the reported marginal effects are lower than would be the case for a fragmented lease.

(with one fragment): the estimated discounts for an additional percentage point of split estate in the one-way fixed effects models are 10 and 4 percentage points higher for the one-way, while in the two-way fixed effects and mixed models the change is a more modest 3 percentage points. Despite this larger marginal effect of split estate, for any of the specifications a lease with two fragments sees not a discount but a premium. These results suggest that bidders are concerned with multiple dimensions of lease property rights. The costs of split estate may be avoidable on a lease with multiple tenures and bidders appear to recognize that fact. Furthermore, when this more complicated environment is considered, the marginal effect of split estate on bonus payments is larger.

Regressing bonus payments on categorical split estate variables yields further evidence of the source of discounts and the relationship between fragments and split estate. While all categories have negative coefficients, the only category that is significant is the wholly-split (100% split) category. The point estimate of the discount is 39 percent in the two-way fixed effect specification and 32 percent when the split-fragment interaction term is added. When the only access to a lease is by split estate, developers anticipate lower values on average. This result also implies that the effect of split estate is not linear; tracts that are entirely split estate sell at significantly lower prices than even those with 75-99% split estate. Results of these specifications are reported in Table 8.

5.3 Quantile Regression Results

Table 9 reports the results of a two-way fixed effects quantile regression investigating how the effects of split estate change across the distribution of bonus payments. Auction- and county-specific fixed effects have been suppressed in the tables and reported standard errors are bootstrapped since there are no underlying distributional assumptions. The total bid is significantly reduced by additional split estate over most of the range. The magnitude of the effect increases across the distribution from no effect for lower bids toward a discount of about one quarter for the 75th and 95th quantiles. At the very high end (95th quantile) the estimate is only very weakly significant. Point estimates are plotted in Figure 2 along with confidence intervals.

More expensive leases represent more likely prospects that are apt to be quite lucrative. In these cases a delay caused by a surface owner can be costly. In the middle of the distribution bidders appear to be taking insurance against particularly troublesome (costly) surface owners by discounting their bids. Cheaper and likely more speculative leases do not exhibit a significant discount for split estate. Such leases may be obtained for exploratory purposes with little expectation of conflict with a surface owner. These results show that the effects of split estate are not uniform for all leases.

5.4 Leasing Stipulations

Lease stipulations imposed by the BLM affect the value of a lease, as presented in Table 10. Starting from a baseline two-way fixed effect specification, each column reports a specification including one of the three main types of stipulation separately and then all three are included together in the last column. Both two-way fixed effects and two-way fixed effects with a bidder random effect are reported with and without the interaction term discussed above. Marginal effects for split estate are calculated for the median lease, as above. The most restrictive stipulation, NSO, leads to a substantial discount of nearly 40% in bonus payments. Controlling for bidder random effects reduces the marginal effect to about 30%, but in either case prohibiting surface occupancy dramatically reduces the value of a lease since developers are forced to use more expensive extraction techniques like directional drilling or rely on drainage from other wells. The discount associated with this stipulation is almost identical to the effect of total split estate in Table 8. The second-most restrictive stipulation, CSU, leads to a smaller but significant discount of about 10% under the two-way models but no significant impact when bidder effects are taken into account. Temporary restrictions, which are by far the most common type of stipulation, have no statistically significant impact. Since temporary closures are typically for a few months of the year, operators apparently have sufficient flexibility in their development programs to schedule entry and drilling during the time of year when the lease is open without increasing their costs.

Including the effects of leasing stipulations confirms the main result of the impact of split estate while controlling for other important factors likely to affect a bidder's valuation of a lease.

5.5 Discussion

These results explain systematic variations in the marginal effects of split estate on lease bonus payments. Bonus bids for federal oil and gas leases are on average 11 to 14 percent lower for each additional percentage point of subsurface-only ownership. The discount is robust across a family of specifications and while taking other important attributes of leases into account. These results provide support for the hypothesis that split estate is more costly to develop. Policy proposals should account for the higher contracting costs inherent on split estate.

The evidence presented here suggests that although developers might try to avoid costs of split estate, they do, on average, expect them. Taking typical bonus payments into account, the magnitude of the discounts that are estimated here is comparable to payments made by operators to surface owners. This relation is suggestive that bidders are in fact discounting their expected future costs into the lease acquisition cost. While split estate does add additional costs, these are expected to be somewhat moderate in comparison to other risks. For the sake of perspective, paying a surface owner a few thousand dollars in order to drill a million-dollar dry hole makes little difference in a firm's bottom line—it is still a loss.

This observation is also useful to understand how the discount changes for different leases. Inexpensive or (probably) speculative leases are apt to see fairly small discounts because surface activity is unlikely to be intensive during the exploration process. More expensive leases convey two important pieces of information: first, it is more likely that larger amounts of resource are in place; second, firms expect to have to drill more wells, or otherwise more thoroughly disturb the surface, creating additional conflict with the surface owner, which will lead to higher transaction costs. As a result, the bid discount gets larger as leases get more expensive. For very expensive leases, where large amounts of gas are almost certain, the costs of dealing with the surface owner shrink in relation to other costs that will be incurred. With high expected revenues, even generous payments to surface owners still leave the prospect of healthy profits.

Accommodation statutes provide an explicit low-cost outside option to developers, but the low incidence of bonding-on suggests that firms are either loath to use that option, perhaps for reputational reasons, or that surface owners actually have low reservation values (perhaps because of their own low outside option). Further research may shed light on which of these explanations is correct. The recent shift in the policy debate away from preventing holdup via accommodation statutes and towards protecting surface owners suggests that political forces are changing. Weakening the accommodation doctrine is likely to increase the discount that developers place on split estate.

Firms continue to bid on and develop split estate minerals, implying that specialization has its place. However, that specialization comes at a cost—the cost of contracting. Which tenure yields larger gains? These results can't answer that question definitively; acquisition is just the first part of the picture. A more complete picture of production from both surface and subsurface and environmental impacts is needed to fully determine which tenure is more efficient.

By using federal mineral rights and federal land, this analysis is limited in one important direction. Describing the value of divided as compared to unified ownership is hard to do since no market for federal land exists. Reverting to private surface and minerals resurrects the problem of endogenous tenures. We would expect severed surface and minerals to be worth more than undivided ownership since severed minerals are more apt to be valuable. In contrast, these results suggest that when we look at exogenously-determined ownership, severed mineral rights are worth less than unified counterparts.

Working from these results, further investigation is needed into why bids are discounted on split estate. Considering the outcomes of development, do bidders discount their bonus payments enough? Or too much? Work on differences in production or environmental impacts might shed more light on the topic. An additional promising topic is to more thoroughly investigate the effect of particular stipulations placed on leases by the BLM. Stipulations have been a policy issue in recent years as they limit lease use in some cases—the results here suggest that they reduce bonus revenue but it is unclear how else they might affect development or how effective they might be in protecting intended service streams.

Tables and Figures

Table 1: Descriptive Statistics for Federal Oil and Gas Leases in Wyoming, 1998-2006

Variable	***Description***	***Mean***	***SD***	***Min***	***25th***	***50th***	***75th***	***Max***
Parcel Variables		N=7334						
Acres	*Number of acres in parcel*	887.2	756.88	3.16	240	640	1420	2560
Bid	*Price paid/acre*	64.33	414.71	2	6	17.5	54	32042
Bonus	*Bid x Acres*	40383	112001	28	2874	9031	32240	4544000
Year	*Year offered*	2001	2.77	1998	1999	2001	2004	2006
% Split	*Percentage of parcel split estate*	38	44	0	0	0.3	97	100
Fragments	*Number of different ownerships in parcel*	1.3	0.52	1	1	1	2	4
Auction Variables		N=53						
Bidders	*Number of winning bidders*	51	11	16 (Feb-03)	44	53	58	73 (Feb-98)
Sale Bonus	*Total bonus paid at auction*	$6.49m	$3.56m	$130k (Feb-03)	$3.36m	$6.21m	$9.36m	$14.6m (Dec-98)
Parcels	*Number of parcels offered*	160	54	25 (Feb-03)	134	160	183	286 (Jun-98)

Table 2: Summary of Sample vs. All Lease Sales, 2000-2005

	Most Parcels	***Fewest Parcels***	***Most Gross Bonus***	***Least Gross Bonus***	***Mean Bonus (Parcel)***
Sample Leases	206 (Aug-00)	25 (Feb-03)	$10.67m (Apr-01)	$130k (Feb-03)	41657
All Leases	222 (Aug-00)	27 (Feb-03)	$10.97m (Apr-01)	$170k (Feb-03)	39266

Table 3A: Description and Incidence of Common Lease Stipulations

N=7010			Affected
CSU	Controlled Surface Use	*Some uses of surface limited*	3276
NSO	No Surface Access	*Lease closed to all surface uses*	183
TLS	Timing Limitation Stipulation	*Lease temporarily closed certain times of year*	4437

Length of TLS	
2 months	92
3-4 months	119
4-5 months	1025
5-6 months	2722
6-7 months	2491
Total number of TLSs	6449

Table 3B: Correlation between Stipulations

	CSU	TLS	NSO
CSU	1		
TLS	0.2844	1	
NSO	0.0815	0.0449	1
% Split	-0.1171	-0.3357	-0.0105

Table 4: One-Way Fixed Effects

Log Bonus	(1)	(2)	(3)	(4)	(5)	(6)
	Auction FE	Auction FE CSE County	Auction FE CSE Bidder	County FE	County FE CSE Auction	County FE CSE Bidder
Acres	0.001053**	0.001050**	0.001053**	0.001014**	0.001014**	0.001014**
	(2.592e-05)	(6.512e-05)	(4.879e-05)	(2.533e-05)	(4.496e-05)	(5.414e-05)
% Split	-0.2244**	-0.2237	-0.2235	-0.1462*	-0.1462	-0.1461*
	(0.04543)	(0.2842)	(0.1173)	(0.06491)	(0.09330)	(0.07401)
Fragments	-0.08414*	-0.08018	-0.08386	0.06744	0.06744	0.06735
	(0.03777)	(0.08677)	(0.04572)	(0.03814)	(0.04630)	(0.04459)
Observations	7334	7327	7333	7327	7327	7326
Number of auctions	53	53	53	N/A	N/A	N/A
R-squared	0.21	0.21	0.21	0.20	0.20	0.20
Number of counties	N/A	N/A	N/A	22	22	22

Standard errors in parentheses ** p<0.01, * p<0.05

Table 5: Two-Way Fixed Effects

Log Bonus	(1)	(2)
	Auction FE County FE	Auction FE County FE Bidder RE MLE
Acres	0.001045**	9.698e-04**
	(2.510e-05)	(2.284e-05)
% Split	-0.1309*	-0.1125*
	(0.06351)	(0.05631)
Fragments	0.1077**	0.1297**
	(0.03715)	(0.03258)
Observations	7329	7328
R-squared	0.98	N/A
Number of bidders	N/A	584

Standard errors in parentheses ** p<0.01, * p<0.05

Table 6: Summary of Point Estimates for Split Estate

	% Split	% Split x Fragments	Combined Effect
Without Interaction			
Auction FE	-0.2244**		
	(0.0454)		
County FE	-0.1462*		
	(0.0649)		
Auction, County FE	-0.1309*		
	(0.0635)		
Auction, County FE Bidder RE MLE	-0.1125*		
	(0.0563)		
With Interaction			
Auction FE	-0.9024**	0.5861**	-0.3163**
	(0.127)	(0.0980)	(0.0509)
County FE	-0.4471**	0.2581**	-0.1890**
	(0.137)	(0.0971)	(0.0721)
Auction, County FE	-0.3501*	0.1880	-0.1621*
	(0.151)	(0.106)	(0.0749)
Auction, County FE Bidder RE MLE	-0.3142**	0.1730	-0.1412*
	(0.118)	(0.0889)	(0.0582)

Standard errors in parentheses (Robust for Interaction Regressions) ** p<0.01, * p<0.05

Table 7: Interaction Models

Log Bonus	(1)	(2)	(3)	(4)	(5)
	Auction FE	County FE	Auction & County FE	Auction FE County FE MLE	Auction FE County FE Bidder RE MLE
Acres	0.001044**	0.001011**	0.001043**	0.001038**	9.685e-04**
	(2.531e-05)	(2.505e-05)	(2.453e-05)	(2.487e-05)	(2.285e-05)
% Split	-0.9024**	-0.4471**	-0.3501*	-0.4692**	-0.3142**
	(0.1268)	(0.1369)	(0.1511)	(0.1346)	(0.1180)
Fragments	-0.3897**	-0.06912	0.008630	-0.04850	0.03845
	(0.06010)	(0.06015)	(0.06778)	(0.06520)	(0.05710)
Fragments*%Split	0.5861**	0.2581**	0.1880	0.2672**	0.1730
	(0.09797)	(0.09714)	(0.1061)	(0.1018)	(0.08893)
Observations	7334	7334	7327	7329	7328
Number of auctions	53	N/A	53	53	53
R-squared	0.21	0.21	0.20	N/A	N/A
Number of bidders	N/A	N/A	N/A	N/A	584
Number of counties	N/A	22	22	22	22

Standard errors in parentheses ** p<0.01, * p<0.05

Table 8: Categorical Split Estate

Log Bonus	(1)	(2)
	Auction FE County FE Bidder	Auction FE County FE Bidder
Acres	9.610e-04**	9.604e-04**
	(2.292e-05)	(2.295e-05)
1-25% Split	-0.05350	-0.02503
	(0.08425)	(0.09952)
26-50% Split	-0.1042	-0.1053
	(0.08391)	(0.08393)
51-75% Split	-0.03270	-0.06337
	(0.08823)	(0.1051)
76-99% Split	-0.02973	-0.09080
	(0.06089)	(0.1289)
100% Split	-0.3276**	-0.3864**
	(0.06935)	(0.1296)
Fragments	0.1130*	0.07106
	(0.04643)	(0.09076)
Fragments*%Split		0.06129
		(0.1141)
Observations	7328	7328
Number of bidders	584	584

Robust standard errors in parentheses ** p<0.01, * p<0.05

Table 9: Quantile Regression

Log Bonus	(1)	(2)	(3)	(4)	(5)
	5th	***25th***	***50th***	***75th***	***95th***
Acres	0.001223**	0.001016**	0.001016**	0.0009616**	0.0008133**
	(0.0000359)	(0.0000451)	(0.0000318)	(0.0000406)	(0.0000460)
% Split	-0.07880	-0.1388	-0.1982*	-0.2424**	-0.2659
	(0.0471)	(0.0986)	(0.0994)	(0.0647)	(0.154)
Fragments	0.1846**	0.1277**	0.06449	0.06016	-0.01488
	(0.0463)	(0.0416)	(0.0477)	(0.0453)	(0.0763)
Observations	7329	7329	7329	7329	7329

Table 10: Stipulation Results

Specification	Baseline	CSU	NSO	TLS	All 3
Without Interaction					
2-Way Variables					
Split Estate	-0.1309*	-0.1278	-0.1244	-0.132*	-0.1208
	(0.06351)	(0.06537)	(0.06535)	(0.06541)	(0.06539)
CSU		-0.1020*			-0.09895*
		(0.0423)			(0.04250)
NSO			-0.3986**		-0.3917**
			(0.1124)		(0.1124)
TLS				-0.001855	0.009569
				(0.0438)	(0.04395)
Mixed Variables					
Split Estate	-0.1125*	-0.09861	-0.09357	-0.1013	-0.09413
	(0.0563)	(0.058)	(0.058)	(0.058)	(0.05802)
CSU		-0.02921			-0.03040
		(0.0378)			(0.03790)
NSO			-0.3011**		-0.2999**
			(0.0983)		(0.09827)
TLS				0.03242	0.03523
				(0.039)	(0.03911)
With Interaction					
2-Way Variables					
Split Estate	-0.1621*	-0.1591*	-0.1553*	-0.1645*	-0.1507*
	(0.06572)	(0.07713)	(0.0772)	(0.07716)	(0.07716)
CSU		-0.09980*			-0.09698*
		(0.0425)			(0.0428)
NSO			-0.3932**		-0.3867**
			(0.109)		(0.109)
TLS				-0.0008934	0.01023
				(0.0438)	(0.044)
Mixed Variables					
Split Estate	-0.1412*	-0.1336*	-0.1277*	-0.1367*	-0.1282*
	(0.0582)	(0.05999)	(0.05997)	(0.05999)	(0.06003)
CSU		-0.02681			-0.02818
		(0.0378)			(0.0379)
NSO			-0.2954**		-0.2943**
			(0.0983)		(0.0983)
TLS				0.03343	0.03599
				(0.039)	(0.0391)

Robust standard errors in parentheses ** $p<0.01$, * $p<0.05$

Figure 1: Unified and Split Estates, Johnson County, Wyoming

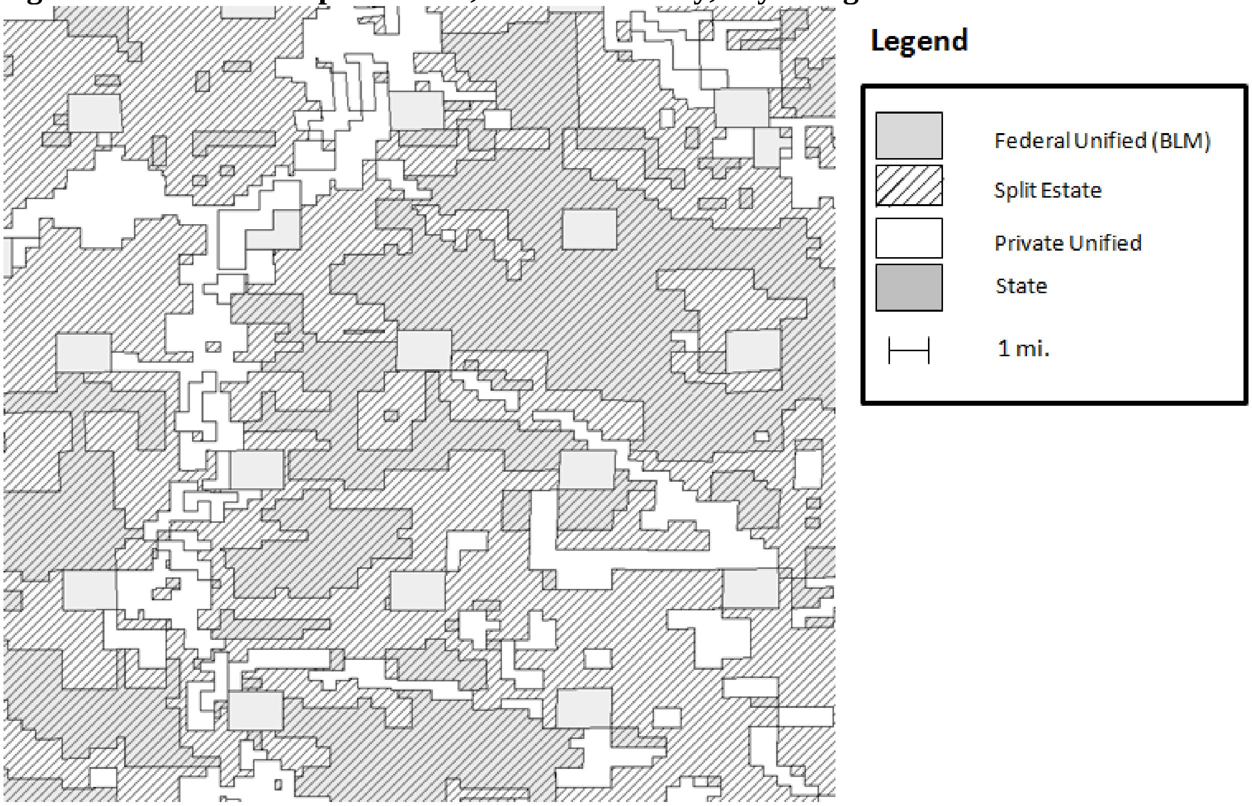
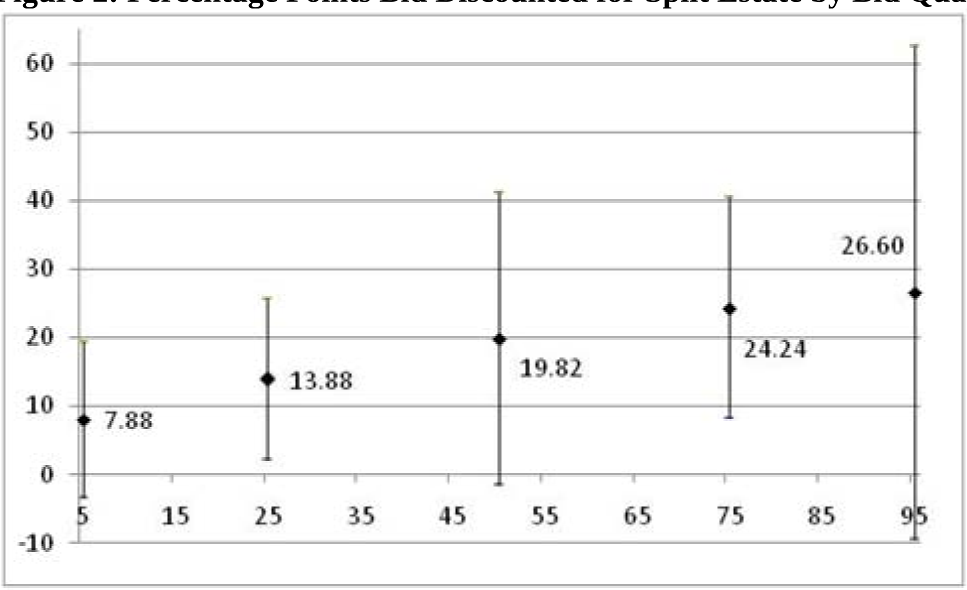


Figure 2: Percentage Points Bid Discounted for Split Estate by Bid Quantile



95% confidence intervals depicted around point estimates from quantile regression. Evaluated at 5th, 25th, 50th, 75th, and 95th quantiles.

Appendix: Results with Log Bid per Acre

Table A1: One-Way Fixed Effects

Log Bid per Acre	(1)	(2)	(3)	(4)	(5)	(6)
	Auction FE	Auction FE CSE County	Auction FE CSE Bidder	County FE	County FE CSE Auction	County FE CSE Bidder
Acres	-2.778e-04**	-2.807e-04**	-2.773e-04**	-2.993e-04**	-2.993e-04**	-2.990e-04**
	(2.459e-05)	(4.808e-05)	(4.124e-05)	(2.403e-05)	(3.797e-05)	(4.613e-05)
% Split	-0.04406	-0.04336	-0.04301	-0.03964	-0.03964	-0.03956
	(0.04311)	(0.2735)	(0.1180)	(0.06159)	(0.09059)	(0.07399)
Fragments	-0.2653**	-0.2618**	-0.2650**	-0.1283**	-0.1283**	-0.1284**
	(0.03583)	(0.08951)	(0.04167)	(0.03619)	(0.04340)	(0.04316)
Observations	7334	7327	7333	7327	7327	7326
Number of auctions	53	53	53	N/A	N/A	N/A
R-squared	0.03	0.03	0.03	0.03	0.03	0.03
Number of counties	N/A	N/A	N/A	22	22	22

Standard errors in parentheses ** p<0.01, * p<0.05

Table A2: Two-Way Fixed Effects

Log Bid per Acre	(1)	(2)
	Auction FE County FE	Auction FE County FE Bidder RE MLE
Acres	-2.731e-04**	-3.124e-04**
	(2.348e-05)	(2.141e-05)
% Split	-0.05735	-0.04974
	(0.05942)	(0.05278)
Fragments	-0.09903**	-0.06160*
	(0.03476)	(0.03055)
Observations	7329	7328
R-squared	0.83	N/A
Number of bidders	N/A	584

Standard errors in parentheses ** p<0.01, * p<0.05

Table A3: Interaction Models

Log Bid per Acre	(1)	(2)	(3)	(4)	(5)
	Auction FE	County FE	Auction & County FE	Auction FE County FE MLE	Auction FE County FE Bidder RE MLE
Acres	-2.826e-04**	-2.997e-04**	-2.736e-04**	-2.734e-04**	-3.127e-04**
	(2.392e-05)	(2.368e-05)	(2.299e-05)	(2.341e-05)	(2.142e-05)
% Split	-0.4272**	-0.08604	-0.1223	-0.09106	-0.09297
	(0.1219)	(0.1296)	(0.1263)	(0.1260)	(0.1107)
Fragments	-0.4380**	-0.1493*	-0.1284*	-0.1108	-0.08115
	(0.05888)	(0.05845)	(0.05626)	(0.06101)	(0.05356)
Fragments*%Split	0.3312**	0.03980	0.05575	0.03395	0.03707
	(0.09539)	(0.09406)	(0.09188)	(0.09538)	(0.08341)
Observations	7334	7327	7329	7327	7328
Number of auctions	53	N/A	53	53	53
R-squared	0.03	0.03	0.83	N/A	N/A
Number of bidders	N/A	N/A	N/A	N/A	584
Number of counties	N/A	22	22	22	22

Standard errors in parentheses ** p<0.01, * p<0.05

Table A4: Quantile Regression

Log Bid per Acre	(1)	(2)	(3)	(4)	(5)
	5th	***25th***	***50th***	***75th***	***95th***
Acres	-0	-0.0002402**	-0.0002562**	-0.0002656**	-0.0003210**
	(0)	(0.0000308)	(0.0000288)	(0.0000295)	(0.0000248)
% Split	0	-0.07597	-0.03915	-0.1462	-0.1125
	(0)	(0.0789)	(0.0889)	(0.0769)	(0.107)
Fragments	-0	-0.02771	-0.09760**	-0.1067**	-0.1862**
	(0)	(0.0534)	(0.0333)	(0.0324)	(0.0622)
Observations	7329	7329	7329	7329	7329

Table A5: Summary of Point Estimates for Split Estate

	% Split	% Split x Fragments	Combined Effect
Without Interaction			
Auction FE	-0.04613		
	(0.0430)		
County FE	-0.04309		
	(0.0607)		
Auction, County FE	-0.05735		
	(0.0594)		
Auction, County FE	-0.04974		
Bidder RE MLE	(0.0528)		
With Interaction			
Auction FE	-0.4272**	0.3312**	-0.09599*
	(0.122)	(0.0954)	(0.0479)
County FE	-0.08604	0.03980	-0.04624
	(0.130)	(0.0941)	(0.0671)
Auction, County FE	-0.1223	0.05575	-0.06658
	(0.126)	(0.0919)	(0.0648)
Auction, County FE	-0.09297	0.03707	-0.0559
Bidder RE MLE	(0.111)	(0.0834)	(0.0546)

Standard errors in parentheses (Robust for Interaction Regressions)
** p<0.01, * p<0.05

Essay 2: Estimating the Impact of Split Estates on Coalbed Methane Production

1. Introduction

In the past decade technological advances and rising energy prices have brought formerly subeconomic energy resources into the limelight. North America has substantial reserves of natural gas trapped in coal, shale, and other geologic formations; these unconventional resources are an important future source of energy. The initial exploitation of these resources has spurred a development boom across the American West that has run up against changing attitudes in the general population. One nexus of sometimes fierce conflict has been between owners of severed mineral and surface rights—so-called “split estate.” This paper examines how conflict between surface and subsurface owners affects production from coalbed methane (CBM) wells in Wyoming. It is expected that split estate adds to the costs of development, making divided tenures marginally less attractive to developers. Wells on divided and undivided tenures are compared by taking advantage of property rights that are effectively randomized with respect to resources. Differences are interpreted as an average effect attributable to the structure of incentives and costs that vary between the two tenures.

Tenures are effectively random with respect to the extensive sedimentary coal deposits in Wyoming that provide the reservoirs for CBM. In order to drill a well that accesses essentially the same subsurface resource, developers can choose a site by tenure. The extent to which this randomization holds is important. Well sites are not random, being selected by firms after consulting professional geologists and engineers who aim to identify the most valuable reserves and exploit them in the most profitable manner. While correctly identifying the location and richness of deposits remains the central challenge of energy production, systematic differences across ownerships are an important internal margin. Since tenures are scattered across the landscape over a range of deposits, the primary concern is that tenures might coincidentally be correlated with the amount of recoverable resource in place, which would bias an estimate of the impact of ownership.

A matching model is used to construct a convincing counterfactual that accounts for observable differences between well sites. This model yields three main conclusions. The first is that divided ownership leads to later exploitation of resources, as measured by time of well application and production. It is hypothesized that this delay is attributable to higher transaction costs incurred on split estate. Second, although total or cumulative production varies across wells on different tenures, this effect is explicable by taking the time in production into account. It does not appear that the delays in production lead to significant differences in the amount of gas produced by wells. Finally, the results can be used to draw conclusions about how firms might choose to report property rights during the development process.

This research contributes to a substantial literature on the efficiency of various property rights regimes and institutional frameworks. It marks an initial attempt at using micro-level production data to evaluate efficiency impacts of property rights allocation on energy production. Divided ownership is ubiquitous in energy production, and while effects of ownership structures have been explored in other contexts,[28] only scant attention has been paid in energy production,[29] with none at a micro level. The individual level avoids problems of aggregation bias and allows a direct interpretation of impacts on the landscape. The implications of property rights for efficient resource use are important as continued development promises to disrupt additional and increasingly valuable surface acreage in coming years. Much of the energy literature glosses over the effects discussed here. While both severed and fractional ownerships have attracted attention in the legal literature (Hill and Rippley (2004), Micheli (2006); Anderson and Smith (1999)), the economic impacts have yet to be explored and quantified.

Split estates arise in several common variations. The simplest case is when a private, fee simple landowner elects to separate the mineral rights from the surface. An owner might do this for several reasons,[30] but is unlikely to do so unless there is some prospect of mineral value. This raises the concern of non-random tenure for alternative well locations, where split estate might indicate higher expected mineral value and thus productivity in the event a well is drilled. However, a split between two private owners is not by any means the only common permutation of ownership. Various levels of government—federal, state, tribal—all end up in split estates with private landowners and each other.[31] A private split estate and private surface over federal minerals are the most common situations: while no statistics for private split

[28] Whinston (2003) contrasts the competing transaction cost (popularly attributed to Williamson) and property rights frameworks (typically associated with Grossman, Hart, and Moore).
[29] E.g., Bohn and Deacon (2000).
[30] See Cox (2001).
[31] A "reverse" split estate, in which the government owns the surface over private minerals is also common, creating use conflicts as private mineral owners seek to extract minerals in spite of public surface use.

estates are available, the federal government recognizes 57 million acres of the West where it holds mineral rights beneath private surface. This paper analyzes the impacts of this ownership combination.

Three facts suggest that federal split estates offer a suitable basis for analyzing the economic role of divided ownership in energy production. First, split and unified ownerships were assigned as a result of homesteading practices during the late 19th and early 20th centuries, long before the unconventional resources that are being extracted today were known to be valuable. The U.S. Supreme Court had to clarify the ownership of coalbed methane gas in 1998 because under some homesteading provisions the federal government retained only the coal, but not the gas trapped in the coal.[32] Based on the assumption that agricultural potential was the primary criterion of homesteaders, and the further assumption that agricultural productivity is unrelated to mineral potential, a perfect instrumental variable for tenure would be the agricultural productivity of land (on a per acre basis) circa 1900.[33] Second, since homesteading in the continental U.S. ended in 1934, the federal government has made very few adjustments to its ownership of surface and subsurface. These holdings are now mandated to be perpetual by statute. Especially as extracting unconventional resources has become economic, the long-term nature of government holdings is useful since it has not been adjusted in light of changing resource values. Third, the terms under which the government leases resources are uniform across different reserves and all operators. This includes such important features of the contract as

[32] *Amoco Production Company v. Southern Ute Tribe*. 526 U. S. 865 (1999)
[33] Thanks to technological advances in agriculture, the ordinal ranking of acres today is likely very different from 100 years ago. In any event, no such data is apparently available.

the royalty payment, which can affect production decisions on the margin (Deacon (1993), Black (2002), Kunce and Morgan (2005)).

Even after deposits are located, producing oil and gas is a complicated process involving high levels of technical sophistication and specific investments. Typically, a well has a high initial production rate that gradually diminishes over time—this is usually modeled as a constant rate of depletion. However, by increasing either subsurface pressure (drive) or permeability it may be possible to increase production later in a well's life. Injecting either gas or liquid into the subsurface can increase geologic drive and reduce lifting costs. Hydraulically fracturing rock increases permeability. One advantage of focusing on coalbed methane is that the technology is relatively simple—typified by shallow, vertical wells.[34] Furthermore, the technology differs little across firms or among wells in similar geologic formations (coals). Little (if any) variation in the timing or amount of gas produced is attributable to differences in production technology. This allows comparison of the timing of production. Production varies in two basic ways: *when* gas comes out of the ground and *how much* gas comes out of the ground. In order to compare across both of these dimensions multiple dependent variables are used: time of entry, time to production, maximum rate of production, and cumulative production. Those measures are discussed further below.

The paper proceeds as follows. The next section expands on how the costs of development differ across tenures. The matching strategy is then discussed, followed by an explanation of the data on CBM wells in Wyoming that are analyzed.

---

[34] Bryner (2003) provides a useful summary of the background of CBM, the simplicity of the technology in comparison to other energy technologies, and some of the particular problems posed by CBM development.

Peculiarities of defining ownership are discussed with an eye towards spotting strategic misreporting by firms in the fifth section. Results are presented in two sections before a discussion section concludes.

2. Comparison of Development Costs across Tenures

Decisions about where and when to develop depend on expected profits. Exploration and development costs are subject to myriad definitions and this section describes how costs vary across tenures at the well level.[35] This model is used to motivate the empirical study rather than make a contribution to the theory of extraction investment. Chermak and Patrick (1995) have previously estimated a well-level cost function, although their model does not address tenure.

Production costs are incurred in three stages: acquisition, development, and operation. Development costs depend on the physical characteristics of a drilling location: pertinent characteristics include the type, depth, and thickness of target formations, distance to pipelines and service facilities, and other physical characteristics such as elevation and terrain. Represent these characteristics with the vector $\boldsymbol{X}$. All of these factors affect how expensive a given well will be to construct and how fast it is likely to be completed. Between acquisition and completion a large portion of the costs of creating a well is apt to be in the drilling of a wellbore. These costs are strongly dependent on the depth drilled, but may also vary by geologic

[35] In an effort to be consistent with Adelman (1992), which addresses the redundancies in cost nomenclature, I use “development costs” in a very specific sense of costs incurred after initial property acquisition and until completion of a well. This usage is analogous to Paddock et al.’s (1988) definition. I use “drilling cost” in a more restrictive sense that entails the costs of physically creating a well. This usage differs from Adelman’s insofar that it does not take into account reserve additions.

complexity. The balance of the costs of development is consumed by overhead and other infrastructure such as roads, power lines, collection pipelines, or water disposal systems. Let $C^D(\boldsymbol{X})$ represent development costs for a well with given characteristics.

One of the most important inputs in the development process is the expertise of geologists and engineers in identifying profitable locations. Once a firm's experts make decisions about when and where to drill, much of the physical construction is contracted to specialists (earthmovers, drillers, welders, etc.). In developing a well, a firm will choose the optimal time of completion that maximizes expected profits. A well will be completed at the time that minimizes costs given expectations about the paths of output prices and available resource. Denote this optimal time of completion as T^*. Choosing costs implies a choice of T^* and vice versa; for example, a firm might elect to spend more (increase C^D) in an effort to complete a well earlier. Technological improvements may outpace rising costs over time, so the time path of development costs is indeterminate.[36]

Construction costs are unlikely to vary across tenures with similar observable characteristics, but the contracting costs incurred in obtaining access from a surface owner are hypothesized to be higher on split estate versus unified. One likely difference is the transaction costs that apply on split estate in order for operators to obtain surface access. This includes the cost of a bond or the payment made in a surface use agreement as well as the costs of reaching an agreement. Let the parameter γ represent the difference in contracting or transaction costs incurred

[36] This has been the subject on the literature of the relationship of drilling costs and technological progress over time. Because drilling costs are strongly correlated with depth, and new technology often allows deeper wells, it appears that technological progress leads to an *increase* in drilling costs. For further discussion, see Copp (1974), Farnsworth and Norgaard (1976), and Copp (1976).

during the drilling process on split estate, but not unified. These costs are expected to be positive, implying that split estate is a more costly tenure to develop, all else equal.

Alternatively, operators may be able to differentially externalize environmental costs on unified versus split estates. Regulations are nominally the same but firms recognize that probabilities of detection and enforcement are low and so may choose to save costs by altering performance. Represent the difference in environmental compliance costs across tenures with a parameter ε. The expectation is that unified rights give a stronger incentive to internalize external effects because the owner controls access to the valuable minerals as well. However, the possibility of closer monitoring by the surface owner prevents signing the parameter. Combining these two parameters, the difference in development cost on split estate (designated by 1) and unified (0) is expressed as follows.

$$C^D(\mathbf{X},1) - C^D(\mathbf{X},0) = \Delta C^D = \gamma + \varepsilon \tag{1}$$

The combined effect of γ and ε is the basis of the test in Kunce et al. (2002), as measured by differences in drilling costs.

Because tenure potentially affects the costs firms incur in constructing wells at physically-similar sites, we expect that the timing of development may also differ. Negotiating surface access with private landowners takes time that a firm might otherwise spend constructing another well. We expect there to be differences in the optimal timing of entry and completion of wells on split and unified tenures precisely because there are cost differences. These differences can be captured in a parameter τ, which is tested below.

$$T^*(\mathbf{X},1) - T^*(\mathbf{X},0) = \tau \tag{2}$$

After a well is completed and production begins, firms incur costs in operating a producing well. These costs depend on the physical characteristics of the wellsite, the amount of production, and the amount of resource in place. Let $C^O(\boldsymbol{X},q(t),Q(t))$ represent these operating costs, where $q(t)$ represents production and $Q(t)$ represents the amount of resource in the ground.[37] Operating costs are incurred over time and firms attempt to maximize profits over time by choosing the optimal time path of extraction, $q(t)$. Operating costs range from mundane maintenance costs, to costs of increasing reservoir pressure or otherwise lifting the resource to the surface, to additional fracturing procedures that increase well production.

Operating costs potentially differ across tenures. For example, concessions made in a surface use agreement may raise variable costs during operation (e.g., more expensive water disposal methods). On the other hand, a developer may reduce operating costs by imposing hard-to-verify environmental impacts on the surface owner. It is reasonable to posit different operating costs, but is not possible to sign the differences. We can express the absolute difference in costs with a parameter η.

$$\Delta C^O = C^O(\mathbf{X},1,q,Q) - C^O(\mathbf{X},0,q,Q) = \eta \qquad (3)$$

Cost differences enter the marginal production conditions. Because the price of gas does not depend on where it was produced, differences in revenues are attributable

[37] This quantity is estimable but probably unknown. If the total amount of resource in place is $\overline{Q}$, then $Q(t) = \overline{Q} - \int_{T^*}^{t} q(s)ds$, where *s* is simply the variable of integration. The assumption that tenures are exogenous to resources implies that $\overline{Q}$ is equal across tenures. The integral represents total production, and $Q(t)$ therefore represents the amount of resource remaining in ground. Because optimal production paths potentially differ due to cost differences, the amount of resource remaining at any given t also potentially differs. In general, more gas in the ground reduces costs, or $\frac{\partial C^O}{\partial Q} < 0$.

only to varying production paths. Profits are likely to differ as a result. We can observe differences in the optimal production path q*. Tests for differences in this optimal production path are conducted below, which also test for differences in marginal production costs.

In a landscape with heterogeneous property rights we might expect the exogenous tenures to affect resource, and thus revenue, potential beyond cost differences. This is true in any formation with significant transmissivity and further motivates the focus of this study on relatively impermeable coal formations with exogenously-determined property rights.

In order to close the model of costs, the third type of costs is the initial acquisition of rights to a well site. Firms have several options for acquiring rights: purchase of whole estate, purchase of mineral rights, leasing of whole estate or minerals, or leasing of operating (majority) interest in minerals. On federal minerals, only leasing is an option. Competition for acquisition of prospects in expected to exhaust supernormal profits. The expected profits of all wells are expected to be equal since the acquisition costs will be higher for more valuable sites. The highest bidder for a lease is the firm with the lowest expected development and operating costs, or the most productive firm. Fitzgerald (2008) has documented systematic differences in lease prices form split and unified federal minerals.

3. Empirical Strategy

The previous section outlines differences in development and operating costs across tenures. The empirical comparisons made below fall into two basic categories.

The first are comparisons of timing of development. One is a comparison of the time of entry. A second is a measure of the time it takes to go from a plan to a completed, producing well. In the terminology of the previous section, this is the time interval between entry (*0*) and completion (T^*). The second type of empirical comparisons are between production characteristics, or features of the q^* production path.

Effects of divided ownership on production must be identified across wells instead of for individual wells over time. The challenge is to determine the appropriate counterfactual. Since other factors that are likely to affect production, such as the amount of resource in place, difficulty of geologic formation, and distance from markets all vary across potential drilling sites, we seek a means to compare wells on tenures that are most similar to one another. Furthermore, because tenure affects profits, we expect that firms select well sites, or observations into our data, on the basis of the variable of interest. Ordinary least squares regression yields biased and inconsistent estimates in this case due to the process of selection.

To overcome these difficulties a matching estimator is used. Matching estimators have been widely used under analogous circumstances, most prominently in labor economics (e.g., Dehejia and Wahba (1999) (2004), Heckman, Ichimura, and Todd (1997) (1998)). Matching allows us to pair or group treated (split estate) wells with untreated (unified) ones that are similar in observable characteristics. Averaging the outcome variables across all pairs (or groups, more generally) yields an estimate of the average effect for the treated population. Extensions of the basic pair-wise matching estimator are possible as each counterfactual can be estimated as an average of a group of "nearby" neighboring observations using regression-predicted values from neighboring observations or kernel-weighting neighboring observations.

Rosenbaum and Rubin (1983) lay out the crucial assumption in all matching models—"selection on observables" or "strong ignorability of treatment." This means that conditional on observable covariates, treatment and outcome are independent. Without this condition any treatment effect is entirely confounded. For example, if all split estate wells were deeper than all unified wells, we wouldn't be able to distinguish the effects of divided ownership from the effects of depth. The assumption is typically expressed in a somewhat weaker form of conditional independence of the mean.

$$\begin{aligned} E(y_0 \mid x, w) &= E(y_0 \mid x) \\ E(y_1 \mid x, w) &= E(y_1 \mid x) \end{aligned} \tag{4}$$

In this notation y_0 represents the outcome for an untreated observation, y_1 represents the outcome for a treated observation, and w is a dummy variable indicating treatment.

Matching does not make typical parametric assumptions on unobservable characteristics. The implicit assumption in using this technique is that observable criteria determine profitability. Seismic reports are important criteria that help firms make investment decisions.[38] Such reports are typically firm-specific and are unobserved in this model. The amount of resource in place is fixed but unknown. Seismic reports give each firm a signal about the value of a potential well site. Since

[38] Report is a catch-all term for the various surveys and models that firms use. Typically these models are constructed by staff geologists and petroleum engineers, explaining why different firms may have different signals of the value of resource available at each location (quantity minus extraction cost). Bohi (1998) emphasizes the importance of new seismographic techniques in assisting identification and recovery of reserves.

we lack complete seismographic information we are forced to make the assumption that selection is based entirely on the observable covariates. We can observe which firm drills a well and make the assumption that information is shared within each firm. This controls for firms that have better average information and that firms have location-specific information advantage based on previous experience.[39]

For a small number of discrete observable criteria it may be possible to match directly, so that for each possible combination of observable criteria, some observations are treated and others untreated. Such a situation is ideal, but as the number of observables increases, it may become more difficult to find perfect matches for each observation. Covariates that vary continuously are also potentially a problem. There are a large number of pertinent observables of well sites, including location, what formations can be accessed, and characteristics of the lease. Rosenbaum and Rubin (1983) introduced the idea of using the propensity score, or conditional probability of receiving treatment, to break the curse of dimensionality for large numbers of covariates. It is also useful for continuous covariates. The propensity score condenses comparison of observations across a number of covariates to the unit interval. The propensity score is a simple way to summarize the information in the covariates and is typically calculated by estimating a nonlinear probability model (usually probit or logit). Dehejia and Wahba (1999) point out that the advantage of this technique is greatest when there are many covariates. In that case it is cumbersome to match across each of the covariates individually. However,

[39] Studying leasing of offshore oil and gas tracts, Hendricks and Porter (1988) found that firms with neighboring parcels had better information about the value of tracts that became available later. This information advantage likely explains the formation of partnerships between companies, which is beyond the scope of this study.

because so much information is condensed into the propensity score, the dimensions in which matched units differ are hidden. Smith and Todd (2005) find that the eventual treatment effects are sensitive to the included variables and functional form of the propensity score equation.

Empirical application of this technique is simplified when the propensity scores have similar distributions for both treated and untreated groups as considerable research effort has been expended on unbalanced and trimmed samples. When the observations differ more widely the mechanics of matching are more important. Balancing the data confirms the similarity of the underlying distributions. For blocks of the propensity score, each main observable (excluding interaction terms) is tested to be sure that there are no statistical differences between the treatment and control groups within that block. If all blocks and all variables pass this test, then the conditional independence of the mean assumption is supported.

Even after a balanced sample is obtained, the mechanics of matching have been the subject of a large literature. Black and Smith (2002) recommend a kernel matching method that accounts for values of the covariates in constructing the counterfactual for each observation. Kernel matching based on propensity scores (which are computed using distributional assumptions) gives the estimator a semiparametric nature. Cameron and Trivedi (2005) cite evidence from comparisons of matching estimators based on Dehejia and Wahba (1999) and (2002) that kernel estimators are less sensitive to the specification of the propensity score that is used. The Epanechnikov kernel is used with a bandwidth of 0.035, which was selected in the manner outlined by Silverman (1986), accounting for the characteristics of the data.[40] Cross-validation of the bandwidth choice is not employed.

Collinearity between variables in the propensity score equation is a problem in these data because many of the explanatory variables pertain to physical characteristics that are likely spatially correlated.[41] Reduced-form propensity score specifications mitigate this problem but create the problem of unbalanced blocks. Therefore selecting the preferred specification faces a tradeoff between these two undesirable properties. Leung and Yu (1996) indicted collinearity as the culprit in differential performance of selection and two-step models. Since selection of well sites is a primary avenue of concern about endogenenity of tenures, their concern is pertinent here.

4. Data

4.1 Provenance

Oil and gas wells in Wyoming are permitted by the state Oil and Gas Conservation Commission (WOGCC). A condition of operation is that monthly reports (Form 2's) be filed with the state. These reports include the amount of oil and or gas produced, the volume of water produced, and the number of days a well operated in each month. These data are self-reported and potentially subject to reporting bias. Missing data is a pervasive problem. The state maintains records for

---

[40] The optimal bandwidth is given by $1.06\sigma N^{-\frac{1}{5}}$. Sensitivity analysis for this choice was performed with bandwidths of 0.10 and 0.01. Results for the primary specifications (corresponding to Tables 6 and 7 below) are presented in an appendix; others are available on request.

[41] The condition number for the full set of variables included in the estimated propensity score equation (which includes higher-order and interaction terms) is 6.54×10^{34}.

all CBM wells and the data used here are drawn from those records. The physical characteristics, including location, formation, depth, and so forth, are drawn from the initial permit application. This initial application includes a report of the tenure on which the well is located. Monthly reports form a detailed picture of the history of each well, permitting comparisons of the production histories.

All CBM wells on record before August 2006 are included in the sample. Table 1 summarizes the wells in the dataset.[42] The earliest permit was granted in 1987, but not until 1996 were more than 100 permits granted in one year. Before that time the technology was still very prospective and experimental.[43]

Regulations require that a well be spudded (drilling started) within 180 days of the application approval. A substantial number of permits expire without ever being spudded, either because firms elect not to drill the well or because they cannot get a drill into the ground within 6 months. The last six months of data also include a large number of wells for which applications have been processed but drilling has not yet started. Actual production typically follows initial drilling by a lag of 1-6 months, time that is spent constructing and completing the well. However, the time to production can be longer than the six months within which firms must spud the well.

Because the latitude and longitude of each well are reported with 3-digit accuracy (on the order of 100 yards), well tenures can also be classified by mapped location. The BLM maintains regularly-updated and highly accurate electronic maps of their holdings, which include both surface tenures and mineral ownerships throughout the state. Since reported and mapped tenures are not always the same, the

[42] Table 1 is split into two parts, as discussed below.
[43] Tenure insecurity is another plausible explanation since the *Amoco v. Southern Ute* decision, which clarified ownership of CBM gas, was not finally decided until 1998.

question of strategic misreporting of tenure is addressed in the next section. Tables 1A and 1B report descriptive statistics for the sample according to each of the respective definitions of tenure.

In order to ensure that there will be overlapping distributions for the treated and control groups, only wells in northeastern Wyoming have been included. The rule that was used is to select wells located north of township 37 and east of range 85. This corresponds to Campbell, Crook, Johnson, Sheridan, and Weston Counties in their entirety, as wells as small portions of Converse, Natrona, and Niobrara Counties. Figure 1 shows the wells that are analyzed.[44] The Powder River Basin is the main watershed in this region that has been one of the leading CBM exploration and production areas in the world during the last decade. Wells in the southwestern part of the state were excluded because there are no CBM wells on split estate there. Although there are many oil or shale gas wells on split estate, the technologies used for those deposits are sufficiently different from those used in coalbeds as to make direct comparisons invalid.

4.2 Dependent Variables

Well productivity can be measured in several ways. In the case of common-pool resources claimed by capture, we may expect to see a “race to exploit” that rewards firms able to produce faster. An alternative motivation is given by the capital intensity of energy production, under which time may be a costly input for developers

[44] None of the sample wells are located in Crook, Weston, or Niobrara Counties even though they were included in the possible area.

using borrowed money. Since physical parameters are on average equal across tenures after matching, the use of other inputs is unlikely to vary significantly.

Four measures are used to assess differences in productivity of wells across tenures. Each of these variables is connected to the amount of underlying natural gas—because property rights are randomly assigned with respect to these resources, we expect that observed differences are due to the treatment of split estate rather than random differences in endowments.

The first measure is the date of application for the permit to drill (APD—a permit to drill). If firms exploit their most profitable opportunities first, we expect to see later access to comparable resources with higher costs, or later entry on split estate.[45] Delayed application is taken as a sign of lower expected profit associated with a drill site. All potential well sites are made available by federal mineral auction, so there is no expectation of bias introduced by the unavailability of split estate locations as compared to unified locations.

The second measure is the time delay between the application and production (TTFP—time to first production). This measure is available only for wells that have produced gas. This eliminates roughly half of the observations since a few wells are dry holes, some permits expire, and many of the later wells in the dataset have not yet produced any gas. Given comparable physical characteristics such as depth, hardness, and location, we expect there to be no difference in construction costs or time. Any difference in this measure is attributable to delays encountered in negotiating for surface access from the surface owner. While it is possible that a

[45] Holland (2003) shows that even in a partial equilibrium setting with limited extraction capacity, the "Herfindahl principle," or extraction in strict order of extraction costs does not necessarily hold.

surface use agreement is signed without specifying well numbers and locations, it is more common that firms must reach terms with the surface owner after deciding where wells will be located, which occurs after application for the drilling permit. Longer delays between application and production are interpreted to be costly and indicative of higher transaction costs. If firms apply for wells before securing access to the surface, we expect to see a delay while access is negotiated. A significant delay should work in the opposite direction of the time of application variable. Anticipating a longer delay from permit to production, firms might apply for permits earlier in order to ensure timely access to resources.

The third measure is the maximum monthly production level. Given that the physical endowments of gas trapped in coal are on average equal across tenures, we would expect these maximum withdrawal rates to be equal, provided that gas is intransient and firms do not risk losing gas to nearby wells by delaying entry. While CBM is generally considered a tight formation, significant differences in maximum production rates are interpreted as a potentially high cost of the delay imposed by additional transaction costs. Wells typically produce at their maximum rate within a month or two of first production, then decline through the life of the well. Maximum production is measured in thousand cubic-feet (MCF) per month.

The final measure that is used here is the cumulative production from wells. This is the ultimate arbiter of value of a natural gas well—how much gas it produces over its lifetime. At modest discount rates production timing differences are likely small provided that the gas is there. It is important to control for the length of time that a well has been in production. Because a well that has been producing for twice as long has produced twice as much gas as another does not mean that it is twice the well. Cumulative production is also measured in MCF, the standard unit of measurement for natural gas.

5. Misreporting

One problem that arises in evaluating the performance of CBM wells on different ownerships is that the classification of a well varies depending on how ownership is defined. There are two ways to evaluate the tenure on which a well is located: the tenure as reported on the permit application and where a well appears when electronically mapped. This section explains the discrepancies that exist between these two methods.

Drilling permit applications require a report of ownership. Slightly over 40,000 CBM wells are included in the data. Thirteen different tenures are represented—unified private, federal, state, and Indian as well as split estates between those parties. The left column of Table 2A details these reports. In rough terms, half of the wells are on private tenures (split or unified), a further quarter on federal unified, and the balance approximately equally divided between federal split and state land. Given the overriding predominance of non-private ownership in Wyoming, these proportions suggest selection of private ownership by developers. Selection could occur at two different points. On one hand, it could be that land claims were made in large part on the mineral value so more valuable deposits ended up in private hands and the government retained the remainder. Alternatively, it might be that the resources are similar but developers chose to locate disproportionately on private land because of lower costs. The novel nature of CBM as a natural gas technology strongly suggests that land claims made a century ago were not predicated on future mineral value for natural gas.   This leaves selection of well sites by developers as the more plausible mechanism. These data do not support tests of hypotheses parsing which of these explanations dominates, although the topic of cost differences between private and federal land has been a addressed in previous research (Kunce et al. (2002)).

The alternative way of identifying tenures is to overlay well locations, which are reported with three-digit GPS accuracy (on the order of a football field) in the permit application, on cadastral GIS maps available from the state BLM office in Cheyenne. These maps are electronic renderings of BLM ownership maps. Official plat maps are held at county courthouses, but the accuracy of the digitized plat maps appears to be high since few errors were encountered with the same cadastral data and oil and gas leases. The cadastral maps only identify 6 different tenures. No data about specific private owners is included. Therefore this method is unable to identify divided private ownerships: it is not possible to identify split estates unless one party is the federal government. Since the maps are continuously updated, it is possible that changes in ownership after the construction of a well would account for error in the mapped tenure. However, since the federal government makes few, if any, adjustments to landholdings, this is not a large source of error for wells on federal minerals. Changes of ownership are common amongst private owners, but these are not changes in type of tenure. The right column of Table 2A reports the mapped well locations. Private tenures again account for roughly half of all wells while federal split is slightly more than a quarter, with the balance divided between federal unified and state ownership. The disparity between reported and mapped tenures entails switching the approximate proportions of federal split and unified wells.

In a perfect world we would expect that the reported tenure for each well location is the same as indicated by the cadastral GIS data. This is not the case, as Table 2B details across all possible combinations of reported and mapped tenures. The main diagonal shows wells that are mapped and reported on the same tenure. For these "correct" wells there is no ambiguity about the tenure. The off-diagonal elements represent cases in which there is a difference between the tenure of a well as indicated by the operator and as mapped given the location provided by the operator. Private tenures include both divided and whole private interests. Unified wells are located where the federal government owns both surface and subsurface. Split refers to the case in which federal minerals are overlain by private surface. State ownership is indicated and sundry ownerships are included in the final category.

Measurement error introduced in recording well locations (usually with handheld GPS units) explains some of the off-diagonal activity. Since tenures are interspersed, sometimes on the scale of 40-acre parcels and often in 640-acre tracts, errors on the order of 200 yards (well within the scale of error of handheld units over the time investigated here) in measurement are sufficient to misrepresent a well location. A 200-yard error moves a well from the center of a 40-acre tract to its edge, which potentially abuts a different tenure. That is, a well could be reported correctly but the reported coordinates are subject to error, introducing confusion when the misrepresented coordinates are mapped. Private wells are the most-reliably reported.

Less than 2% of wells reported on private ground turn out to be elsewhere and only 3.6% of wells mapped on private ownership are reported elsewhere. These proportions are consistent with measurement error in recording well locations. Given the fragmentation of state holdings, the associated errors are somewhat larger, but still within plausible bounds for measurement error. Sundry other holdings also exhibit a higher percentage of misreporting, attributable to the imperfect alignment of reported and mapped tenure types (reverse split estates are very hard to identify with cadastral GIS).

Well locations that are mapped as federal unified are only reported otherwise 3.1% of the time. Wells that are reported as being on federal split also usually are—only 2.4% of such wells appear on other tenures when mapped. These figures are commensurate with the background measurement error of 2-4% that was observed on private ground. However, two-thirds of all wells that are mapped on split estate are reported as being on unified federal ownership. Given a presumed background error rate on the order of 2-4%, this anomaly is substantial enough to suggest possible strategic behavior. Table 2C reports the number of CBM wells that are both mapped and reported on federal minerals in northeastern Wyoming. Requiring a full vector of covariates and limiting the spatial extent of the comparison excludes 995 wells, which amounts to 6.95% of all wells that are both reported and mapped on federal minerals. These excluded wells are proportionately distributed across the alternatives in Table 2C.

Table 2C raises the question: why do firms appear to overwhelmingly misreport wells that are in fact on split estate as being on unified federal tenure?

Three possible explanations present themselves. First, this could simply be a magnification of measurement error across all tenures that we suspect in Table 2B. While we cannot reject the presence of measurement error across unified and split federal tenures, the disparity between the misreporting of split and unified wells and the background levels of apparent measurement error is striking.

A second possible explanation is that paperwork for well applications is often filled out by office personnel unfamiliar with the actual situation on the ground. It is possible that office personnel are not even located in the same state and may be ignorant of the importance of split estate. This explanation dismisses misreported wells as random errors by uninformed office staff. Severed ownerships are pervasive in energy development and no office staff in any energy company could long exist without developing a nuanced understanding of split estates. Some evidence that misreporting may be due to lack of understanding is presented in Table 3, which shows when well applications were made. The first and fourth columns are correctly reported wells on unified and split tenure, respectively. The second column is wells reported on unified but mapped on split—the third column is the converse.

Before 1999 every well that was drilled on split estate was reported as being on federal unified. After that time the incidence of misreporting dropped precipitously, as shown in the final column, which reports the percentage of mapped split wells reported as unified. During the debate leading up to passage of a state law (W.S. 30-5-401) over obligations of energy developers to split estate surface owners, it is clear that firms were much more careful in recording tenures accurately. The act was passed in 2005, and in 2006 the level of misreporting of wells that are mapped on split estate (4.0%) was more commensurate with measurement error. So while it is clear that the reporting has become more accurate over time, it is does not explain why firms disproportionately tried to misreport split tenures as unified but not vice versa. This leads to a third line of inquiry.

The third plausible explanation is that we are observing strategic behavior by firms. Misreporting is subject to fines if it is detected and punished. If misreporting is strategic, it must be done in cases in which the firm expects benefits to exceed the costs of penalty. What incentive could a firm possibly have to misreport the tenure of a well site? Firms typically apply for well permits as they are planning whole developments of CBM wells. At times they may concurrently be negotiating terms of surface access with private split estate owners since development plans are fluid and commonly change given information that is revealed during the initial drilling process. In order to be granted a drilling permit, firms must show evidence of a surface use agreement or obtain a waiver from the landowner. In an effort to expedite the process of well permitting and construction, a firm might neglect to inform the state of the true tenure of the site. This increases the chance of a fast permit approval and hopefully a quick completion. This explanation implies that firms selectively choose to “accidentally” misreport the tenure that a well lies on. As we turn to the results we will ignore the misreporting issue for the moment but return to it shortly.

6. Results

6.1 Balancing Tests

The typical requirement for sample balancing is that the mean propensity score be statistically indistinguishable across the treatment for blocks of the propensity score. Within those blocks, the primary covariates (those of economic importance—not including higher-order or interaction terms included in the propensity score specification) should also be statistically indistinguishable. This ensures that conditional mean independence is satisfied.

Table 4 displays the distribution of propensity scores across the treatment as defined by reported and then by mapped split estate. Figures 2A and 2B show the distributions visually. There are 19 blocks for reported tenure and 16 blocks for mapped; visual examination shows that the support of the propensity score is quite good in both cases. This is an artifact of the tenures themselves being largely randomized. However, in some blocks for some covariates the mean values of the treated and control groups are significantly different, which reflects how the observed well sites represent an imperfectly-randomized subsample of locations.

Closer examination of these failures in balance reveals that statistically significant differences mask small physical differences. Table 5 summarizes the primary covariates that are not balanced along with the absolute magnitude and standard error of the difference between unified and split wells. For example, in block 6 of the reported split estate specification, the township variable is not balanced—split estate wells in that group are located 0.766 townships further south than unified wells, which is equal to a distance of 4.6 miles. The township variable is balanced on average and across most of the other blocks. These differences appear to be statistically significant for some subset of the blocks of propensity score but not economically meaningful. The failure of balancing tests, and therefore the conditional independence of means assumption, is interpreted as an artifact of the imperfect randomization of tenures to resources. The following sections report results from matching models using the propensity score specifications reported in Tables 4 & 5.

6.2 Basic Results for Reported Split Estate

The unmatched differences between reported split and unified wells are striking. On split estates entry (as measured by date of drilling permit) is later by 2-1/2 years, wells take 55 days longer to get into production, monthly peak gas production is 2000 Mcf lower, and cumulative production is 42,000 Mcf lower. The first column of Table 6 summarizes these results. However, after matching wells (or well sites) that are similar in terms of observable characteristics, we see that the differences between tenures are less striking. The delay in entry remains significantly different, but its magnitude is much lower than in the unmatched case. On average, firms seek drilling permits on split estate 11 months later than for comparable wells on unified estate. This provides support for the hypothesis that firms view split estate as being potentially costly.

The delay from permit to production (TTFP) and peak monthly production do not yield statistically significant differences in the matched model. Like the date of entry (APD), the point estimates are smaller in magnitude in the matched model.

That is, the unmatched differences pick up fundamental differences between wells in the two groups. This is particularly important in the context of the maximum gas production, since we would expect peak production to be comparable from similar reserves. For both measures the standard error of the difference is larger in the matched model.

Cumulative gas production is also not significantly different in the matched model after taking the number of days that a well has been operating into account. Earlier entry on unified estate implies that unified wells have operated much longer, so the unmatched difference picks up the time effect through production. The pairwise correlation between entry date and total days in production is 0.53.

6.3 Basic Results for Mapped Split Estate

Like reported split estate, mapped split estate shows significant differences between split and unified wells across the whole unmatched sample. Implication of the large change in the definition of the treatment group and its attendant effect on the outcome variables are taken up in the next section on misreporting. However, the unmatched differences for mapped tenure are far different than for reported. Split estate is developed almost 16 months earlier with a shorter delay from entry to production by three months. Peak monthly gas production is lower and cumulative production is higher on mapped split estate.

Table 7 reports the matching results for mapped split estate. As in Table 6, the unmatched differences between wells are significant across all measures. However, by matching wells much of the difference in explained through observable characteristics. Time of entry remains significantly different after matching and the other production variables lose statistical significance. According to the map, firms apply for split estate wells about 7 months earlier than on unified. The implications of this perverse result using the mapped definition are discussed further in the next section. All standard errors are larger in the matched model. When total number of days of production is taken into account, the cumulative gas produced variable remains insignificant.

6.4 Comparison to Regression Results

One way to assess the matching estimates is to compare them to results of a linear regression. Because well sites are selected and property rights play a role in that selection, we expect that linear regression results are potentially biased and inconsistent. Despite these known shortcomings, linear regressions can serve as a "reality check" on the magnitudes of the matching estimates. Table 8 presents results of linear regressions with fixed effects for formation, county, and operator.[46] The first column reports the estimates for the effect of reported split estate, which can be compared to matching results in Table 6. Initial entry is almost 14 months later on split estate, slightly more than the matched estimate. The delay from permit to production is almost 4 months, about three times the estimate in Table 6, which was not significant. No significant differences in either maximum monthly production or total production are detected. When the linear model includes the total number of

[46] The estimated specifications are of the form:
$APD_{ifco} = \mathbf{X\beta}_{ifco} + \alpha SPLIT_{ifco} + \gamma_f + \gamma_c + \gamma_o + \varepsilon_{ifco}$ where γ_j represents fixed effects for formation, county, and operator.

days in production, as the matched model did, it also shows no significant difference in cumulative production.

The second column reports the effect of split estate as mapped. No significant difference in time of initial entry is detected, but the sign is opposite of the initial matching regressions, suggesting that split estate is associated with later entry. The delay to production is significant and positive, in comparison to the negative and insignificant estimate in Table 7. No significant differences in either maximum or cumulative production are detected, consonant with the matching models.

Table 9 reports linear regressions in which the split estate variables have been replaced with the estimated propensity scores, as calculated with either reported or mapped split estate as the dependent variable. These scores range between 0 and 1 instead of taking one value or the other. The table reports the point estimates for the effect of estimated propensity score, the distributions of which are shown in Figures 2A and 2B.

Substituting the propensity score affects the point estimates for reported tenure. The delay in time of entry approximately doubles to 27 months and the delay from entry to production increases by half a month to just over 4 months. Maximum monthly gas production is significantly lower on split estate but cumulative production does not differ. Using the propensity scores also gives different estimates for mapped split estate. The difference in time of entry is slightly larger than that reported in the matched specification in Table 7. Significantly shorter time to production is difficult to interpret. Peak production is not statistically different but cumulative production is larger on split estate, even after controlling for days in production.

6.5 Formation-Specific Matching

One way to reduce balancing problems is to concentrate on subsets of wells. Limiting the data to particular coal formations eliminates potential heterogeneity. Table 10 reports the matching results for the Wyodak Coal, one of the major coal formations in the Powder River Basin, using the reported tenure. The time of entry is later on split estate, but about a month smaller difference than in the pooled sample reported in Table 6. None of the other dependent variables shows a significant difference, which is parallel to the pooled results. Table 11 shows the matching results using the mapped tenure definition. None of the dependent variables indicates a significant difference in this specification. This result differs from the pooled results reported in Table 7 in that the time of entry differed significantly by tenure in that case.

Table 12 reports the reported effects for the Big George coal, a somewhat deeper coal located near the Wyodak formation. Generally speaking, the Big George has been developed after the Wyodak. The time of entry differs in this case, but is very close to the pooled estimates reported in Table 6. The delay from entry to production and the production variables do not vary significantly with tenure for the Big George, mirroring the pooled results. Table 13 completes the series, reporting the mapped effect in the Big George. The only significant impact is the delay from application to production, which differs from the pooled results reported in Table 7. However, there is still no significant difference in the production profiles.

7. Misreporting Results

7.1 Explaining Misreporting

The variation in the definition of split estate between reported and mapped tenures raises a compelling question. Comparing outcomes for wells that are correctly and incorrectly reported sheds some light on this topic.[47] Table 14 reports the differences in the production measures across the split estate for wells that are correctly reported. That is, the control group is unified wells that are reported and mapped as unified, and the treatment group is wells that are reported and mapped as split. The left-hand panel shows the unadjusted differences for the whole sample: significant differences exist in time of entry (APD), peak gas extraction, and cumulative gas extracted. Unified wells see application on average 10 months earlier than split estate wells. No significant difference in delay to production (TTFP) exists between tenures. Unified wells have higher peak production and higher cumulative production.

The right-hand panel reports the differences for the subsample of wells with complete data that permits estimation of a propensity score. The unmatched differences in the matching sample mimic the results for the whole sample. After wells are matched by a kernel estimator there are no significant differences with a

[47] Throughout this section kernel matching models with a bandwidth of 0.035 are the baseline. Additional results using a bandwidth of 0.1 are presented in Appendix 2 and are occasionally referenced throughout this discussion.

bandwidth of 0.035. Even with the (more efficient but potentially biased) wider bandwidth of 0.10 the only significant difference between unified and split wells that are correctly reported is in 3.5 months difference in time of application (APD). Delay to production and both maximum and cumulative production yield no significant difference across tenures for all bandwidths. These results provide a useful robustness check for the main results presented above. Discounting the problem of misreporting entirely by dropping all wells for which there is a question about tenure, the data provide weak evidence that firms enter split estate later than unified. This difference does not ripple through the production process since after wells are permitted no significant difference in the production measures used here is found.

Table 15 presents results pertaining only to wells that are apparently misreported: either a unified report but mapped split or vice versa. The only significant unmatched difference is that wells reported on unified estate precede those reported on split estate by 40 months, or over three years on average. Given the results presented in Table 3, it should come as no surprise that among misreported wells, those erroneously reported as unified preceded others by a substantial margin. However, when wells are matched, the difference in time of application decreases to about 26 months. This suggests that wells misreported as unified predated wells misreported as split, which most likely represent cases of measurement error by GPS units, by over two years. This result corroborates the data presented in Table 3. The matching model also shows that there is a significant difference in the cumulative production in favor of wells that are reported as split but in fact on unified. The difference in cumulative production is a substantial 110 MMcf.

Tables 16 and 17 report comparisons of wells reported on unified and split tenures, respectively, comparing those indicated as misreported after mapping to those mapped and reported on the same tenure. There are no significant differences among all of the measures for misreported wells. The lack of significant differences between misreported and correctly reported wells lends some credibility to the hypothesis that misreporting is a result of random errors, simply a result of either errors in cadastral GIS data or in recording well locations with handheld GPS units. Table 18 tells a corroborating story about wells mapped on unified estate. The differences between misreported and correctly reported wells are not statistically significant.

We suspect that split estate imposes additional transaction costs and that firms seek to avoid these costs. Assuming that surface owners prevent costless access to the surface and that measurement is accurate, all of these wells are subject to potentially higher transaction costs. Might strategic motives impel a firm to misreport the tenure, potentially incurring a substantial fine? Indeed, in both the whole sample and among matchable wells we see significant differences between those wells that are misreported and those that are not. Table 19 compares outcomes for wells mapped on split estate. The time of application is about 9 months earlier for misreported wells, an empirical regularity explained by the time path of misreporting. However, there are no significant differences in the delay from permit to production (TTFP) for misreported wells, or in peak or cumulative production. Using a slightly larger bandwidth of 0.1, we find that misreported wells appear almost a year and a half earlier (17 months). Firms manage to shave an average of 5 months off the time from permit to production and cumulative production is higher by 40,000 Mcf.[48] This difference in cumulative production takes days in production into account. Firms enjoy shorter delays to production (on the order of 5 months) as well as higher cumulative production, all else equal. This provides evidence in support of an incentive for firms to fudge their reports of the tenure in order to expedite development. The wells that prove to be reported as unified when they are mapped on split turn out to be valuable and productive wells. The risk that a surface owner might pose a barrier to production is more costly under these circumstances so firms appear to be more willing to bend the rules in order to get access to valuable deposits. The fact that firms enter these better prospects almost one and a half years earlier on average provides some support for the assertion that firms exploit their best prospects first, although the misreporting issue is confounded with the later heightened awareness of split estate concurrent with the passage of the Surface Owner's Protection Act.

7.2 Comparison to Linear Regression

Results of linear regressions exploring the effect of misreporting are reported in Table 20. The first columns report the effect of reported tenure. The marginal effect of split estate on time of application (APD) is a delay of seven and a half months. However, misreported wells appear about 10 months earlier. The effects for mapped split estate are similar: six months later for split estate but 17 months earlier

[48] These results are reported in Table 6 of Appendix 2.

for misreported wells. These results confirm the results of Table 3, indicating that misreported wells are disproportionately earlier in time of entry. The effect of misreporting on the delay from entry to production is unambiguously negative—three months in the case of reported split estate and about 4 months in the case of mapped split estate.

Comparing maximum production levels shows no significant effect for either reported or mapped split estate. Misreported wells using reported tenure indicates a significant negative impact, which is a perverse result. However, the effect of misreporting on cumulative production shows significant and positive differences, albeit at a marginal significance level for mapped tenure. These effects take time in production into effect. The marginal effect of reported split estate is also positive and significant, which was not expected.

Table 21 reports similar specifications using propensity scores instead of indicator variables for split estate. Reported split estate is still associated with 19 months' later entry, and misreported wells were initiated 14 months earlier. The mapped propensity scores show that split wells were started almost 10 months earlier and misreported wells were 5 months later than correctly reported wells. These estimates are similar to those in Table 9. The effects of tenure on delay from entry to production are also similar to Table 9. Misreported wells exhibit a shorter delay to production for reported tenures and no significant effect for mapped tenures.

The effects of tenure on the production outcomes are similar to those reported in Table 9. The effect of misreporting on maximum monthly production is significant and negative for reported tenures, but there is no significant effect on mapped tenures.

Misreporting has no significant effect on cumulative production for either definition of tenure.

8. Discussion

Three basic conclusions recur throughout these results. First, there is a significant difference in time of entry between split and unified wells. The delay is between 3.5 and 11 months for wells reported on split estate. Something, presumably anticipation of higher transaction costs, compels firms to make well applications later on split estate. Second, despite this delay, the other production outcomes do not show significant differences in the main specifications. Differences in cumulative production from unified and split estate wells are explicable by comparing to other wells that are similar in terms of observable characteristics, including the number of days that the wells has produced. These production results are equally true of reported and mapped tenures. This leads to two important conclusions about the effect of split tenures. Delay in entry does not lead to reduced production from split estate wells by rule of capture, where other wells extract resource in place. So even though firms wait longer to drill wells on split estate, this waiting is not costly to them in terms of foregone gas production. The other inference is that the differences between split and unified wells give rise to fixed as opposed to variable cost differences. Once the time cost of delay is paid, firms don’t continue to pay a variable cost for each unit of gas extracted.

The third basic conclusion is that there is some evidence to support a conjecture that firms have an incentive to misrepresent the tenure at a well site in order to expedite development and eventual production. Misreporting is disproportionately of wells on split estate as unified, with the possible benefit being a shorter time interval to production. Indeed, the results indicate that the delay to production is shorter and the production is faster and larger for misreported wells.

Beyond these conclusions, this work raises a number of interesting questions for further research. Do resource characteristics (e.g., transmissivity or permeability) affect the impact of tenure? The formation-specific matches do yield slightly different estimates, which may be attributable to different physical characteristics of the coal. Does information (relative or absolute) about the underlying geology affect the relative ranking of tenures? Information costs are one form of transaction costs; given the fundamental information problem of energy exploration and production, tenures may have different effects depending on the degree of uncertainty about the underlying geology. These questions are left for future work.

Table 1A: Summary of Well Observations by Reported Tenure: All of Wyoming

Reported	Federal Unified	Federal Split	**Federal Minerals**	Private Unified	Private Split	State	Other	**Total**
Denied	71	33	104	331	3	66	8	512
Expired	2678	449	3127	5045	18	1105	111	9406
Waiting	51	70	121	51	32	9	2	215
APD	1075	2095	3170	625	700	281	101	4877
Not Drilled	3875	2647	6522	6052	753	1461	222	15010
Spud	405	343	748	290	152	141	29	1360
Dry Hole	20	0	20	14	0	4	0	38
Shut In	857	284	1141	2309	157	575	35	4217
Abandoned	333	11	344	1135	7	175	0	1661
Producing	4878	763	5641	10448	62	1792	43	18148
Drilled	6493	1401	7894	14196	378	2687	107	25424
No Data	6	1	7	22	0	1	0	30
TOTAL	**10374**	**4049**	**14423**	**20270**	**1131**	**4149**	**329**	**40464**
Produced	4711	762	5473	11182	73	1714	160	18602

Table 1B: Summary of Well Observations by Mapped Tenure: All of Wyoming

Mapped	Federal Unified	Federal Split	**Federal Minerals**	Private	State	Other	**Total**
Denied	20	99	119	327	64	1	511
Expired	675	2596	3271	5053	1063	18	9405
Waiting	32	91	123	83	9	0	215
APD	994	2207	3201	1352	276	48	4877
Not Drilled	1721	4993	6714	6815	1412	67	15008
Spud	304	442	746	449	124	4	1323
Dry Hole	6	14	20	15	3	0	38
Shut In	391	771	1162	2551	474	5	4192
Abandoned	32	323	355	1149	157	0	1661
Producing	970	4102	5072	8175	1437	31	14715
Drilled	1703	5652	7355	12339	2195	40	21929
No Data	1	5	6	23	1	0	30
TOTAL	**3476**	**11212**	**14688**	**21772**	**3889**	**151**	**40460**
Produced	843	4674	5517	11408	1642	33	18600

Table 2A: Summary of Reported and Mapped Tenure of All CBM Wells in Wyoming

Tenure	Reported	Mapped
Private	21397	21772
Unified	10400	3476
Split	4049	11212
State	4149	3889
Other	465	111
Total	40460	40460

Table 2B: Reported vs. Mapped Tenure of All CBM Wells in Wyoming

	Mapped					
	Private	**Unified**	**Split**	**State**	**Other**	**Total**
Private	20979	24	312	82	0	21397
Unified	79	3367	6927	7	20	10400
Split	28	69	3951	1	0	4049
State	476	16	13	3634	10	4149
Other	210	0	9	165	81	465
	21772	3476	11212	3889	111	40460

Table 2C: Reported vs. Mapped Tenure of Matchable CBM Wells in NE Wyoming

	Reported		
	Unified	**Split**	**Total**
Unified	2717	6737	9454
Split	62	3,803	3,865
Total	2779	10540	13319

Table 3: Time Paths of Well Reporting

Year	1	2	3	4	Total	Pct. Split Wells Misreported
	U-U	U-S	S-U	S-S		
1987	0	4	0	0	4	100.0
1988	1	7	0	0	8	100.0
1989	1	5	0	0	6	100.0
1990	0	10	0	0	10	100.0
1991	1	3	0	0	4	100.0
1992	2	11	0	0	13	100.0
1993	0	1	0	0	1	100.0
1994	1	8	0	0	9	100.0
1995	1	18	0	0	19	100.0
1996	4	121	0	0	125	100.0
1997	19	96	0	0	115	100.0
1998	30	206	0	0	236	100.0
1999	189	1107	2	25	1323	97.8
2000	102	735	0	6	843	99.2
2001	158	1601	5	121	1885	93.0
2002	135	652	1	162	950	80.1
2003	474	602	2	248	1326	70.8
2004	600	898	12	766	2276	54.0
2005	770	613	10	1335	2737	31.5
2006	702	47	30	1140	1919	4.0
Total	3199	6745	62	3803	13809	63.9

Table 4: Observations by Propensity Score Block

Reported SE

Block	Score	Control	Treated	Total
1	0	2196	49	2245
2	0.025	282	12	294
3	0.05	640	20	660
4	0.1	2408	346	2754
5	0.2	800	261	1061
6	0.25	383	162	545
7	0.275	284	190	474
8	0.3	449	239	688
9	0.35	224	126	350
10	0.375	180	160	340
11	0.4	690	602	1292
12	0.5	564	579	1143
13	0.6	231	391	622
14	0.7	103	235	338
15	0.8	27	222	249
16	0.9	18	271	289
		9479	3865	13344

Mapped SE

Block	Score	Control	Treated	Total
1	0	23	432	455
2	0.1	58	10	68
3	0.2	106	19	125
4	0.25	82	22	104
5	0.275	59	40	99
6	0.3	435	270	705
7	0.4	234	175	409
8	0.45	213	213	426
9	0.5	368	391	759
10	0.6	250	451	701
11	0.7	335	1049	1384
12	0.8	224	1000	1224
13	0.85	253	1547	1800
14	0.9	114	1965	2079
15	0.95	30	1194	1224
16	0.975	24	2020	2044
		2808	10798	13606

Table 5: Unbalanced Blocks of Propensity Score with Differences for Primary Variables

Reported SE

Block	Elevation	Township	Range
2	230.548*	-3.177**	
	(90.847)	(1.095)	
3			-2.391**
			(0.485)
5	58.892*		
	(23.359)		
6		-0.766*	
		(0.355)	
7	-85.838*	0.781*	
	(28.060)	(0.360)	
10		1.166*	
		(0.481)	
11	-61.716*		
	(26.006)		
12	-80.179**		0.281*
	-28.913		(0.114)
16	-315.716*		1.717*
	(140.891)		(0.858)

Mapped SE

Block	Elevation	Township	Range
2	-124.731**		
	(30.541)		
3		-1.397**	0.396*
		(0.410)	(0.187)
4			0.532*
			(0.217)
7	123.305**	-1.749**	-0.401**
	(22.817)	(0.319)	(0.135)
8	64.441**	-1.009**	
	(24.724)	(0.328)	
9	63.019**		
	(21.866)		
14	-156.598**	1.964**	0.983**
	(35.228)	(0.404)	(0.206)
15			1.154*
			(0.510)

Table 6: Effect of Reported Split Estate

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	-30.983**	-10.718**	9350	3829	13179
(Months)	(0.539)	(0.846)			
APD to Production	1.843**	1.023	2486	501	2987
(Months)	(0.401)	(0.732)			
Product Measures					
Maximum Gas	-2037.902**	-339.965	5509	1001	6510
(MCF/Month)	(303.107)	(473.227)			
Cumulative Gas	-42012.440**	6461.437	5509	1001	6510
(MCF)	(4188.714)	(6508.836)			

Table 7: Effect of Mapped Split Estate

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	15.583**	6.821**	2798	10366	13164
	(0.658)	(1.420)			
APD to Production	-2.953**	-1.103	256	2828	3084
	(0.545)	(1.571)			
Product Measures					
Maximum Gas	-632.839*	89.641	1226	5411	6637
	(281.595)	(1103.336)			
Cumulative Gas	20265.536**	-8567.103	1226	5411	6637
	(3941.377)	(12550.051)			

Table 8: Regression Results

	Reported	Mapped
Time Measures		
APD	-13.748**	-2.5507
	(0.3673)	(2.1028)
APD to Production	3.6587**	1.3531*
	(0.4620)	(0.6767)
Product Measures		
Maximum Gas	643.24	216.36
	(415.61)	(604.89)
Cumulative Gas	684.41	5737.1
	(3253.8)	(4718.7)

Table 9: Regression Results with Propensity Score

	Reported	Mapped
Time Measures		
APD	-26.959**	9.7257**
	(1.7794)	(1.8010)
APD to Production	4.1605*	-8.9449**
	(2.0264)	(1.9634)
Product Measures		
Maximum Gas	-4691.7**	-2427.8
	(1759.7)	(1768.5)
Cumulative Gas	-1891.4	31856*
	(14002)	(13804)

Table 10: Wyodak Coal Matching Results: Reported

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	-15.889**	-10.028**	1467	225	1692
(Months)	(1.346)	(1.703)			
APD to Production	1.420	0.660	702	89	791
(Months)	(0.946)	(0.982)			
Product Measures					
Maximum Gas	58.584	-193.779	1105	114	1249
(MCF/Month)	(531.804)	(599.367)			
Cumulative Gas	-5118.559	9659.088	1105	145	1249
(MCF)	(9832.110)	(10628.276)			

Table 11: Wyodak Coal Matching Results: Mapped

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	12.083**	1.518	155	1543	1698
(Months)	(1.617)	(2.860)			
APD to Production	1.045	3.750	31	740	771
(Months)	(1.560)	(8.051)			
Product Measures					
Maximum Gas	724.005	-1720.645	85	1152	1237
(MCF/Month)	(678.060)	(1024.679)			
Cumulative Gas	44750.258**	-28141.682	85	1152	1237
(MCF)	(12493.093)	(19264.671)			

Table 12: Big George Coal Matching Results: Reported

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	-9.353**	-10.871**	2504	1509	4013
(Months)	(0.565)	(0.631)			
APD to Production	-0.121	2.125	389	97	486
(Months)	(1.025)	(1.504)			
Product Measures					
Maximum Gas	-2183.146**	-479.031	1566	352	1918
(MCF/Month)	(736.930)	(880.571)			
Cumulative Gas	-12687.864	3244.076	1566	344	1910
(MCF)	(7636.648)	(10477.425)			

Table 13: Big George Coal Matching Results: Mapped

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	0.950	3.943	1371	2680	4051
(Months)	(0.597)	(2.102)			
APD to Production	-5.909**	-11.674**	78	400	478
(Months)	(1.082)	(5.047)			
Product Measures					
Maximum Gas	-1588.138**	1958.455	696	1243	1939
(MCF/Month)	(598.903)	(4032.779)			
Cumulative Gas	9276.880	28239.764	696	1243	1939
(MCF)	(6254.808)	(35211.096)			

Table 14: Correct Wells Only

Treatment==Split

	Total Sample		*Matchable Sample*		
	Treated	Difference	Treated	Difference	Matched
APD	3803/6520	-10.305**	3573/6272	-10.089**	-2.499
		(0.610)		(0.572)	(1.781)
TTFP	503/759	1.227	474/693	-0.469	2.496
		(0.766)		(0.742)	(2.251)
Peak	1005/2210	-2289.595**	963/2101	-2293.021**	1640.765
		(433.370)		(477.390)	(2270.473)
Total	1005/2210	-19195.05**	963/2101	-18218.085**	21789.112
		(4664.307)		(5095.049)	(24044.699)

Table 15: Misreported Wells Only

Treatment==Reported Unified, Mapped Split

	Total Sample		*Matchable Sample*		
	Treated	Difference	Treated	Difference	Matched
APD	6737/6799	40.615**	5656/5717	40.993**	25.966**
		(3.029)		(3.843)	(5.230)
TTFP	2403/2409	0.281	1/7	1.432	0
		(2.178)		(3.280)	.
Peak	4503/4518	-2735.244	2861/2876	-1944.368	-6048.5778
		(2020.261)		(2246.659)	(2727.163)
Total	4503/4518	-36110.04	2861/2876	-25698.538	-110444.428*
		(34229.69)		(35217.218)	(52665.706)

Table 16: Reported Unified Wells

Treatment==Misreport

	Total Sample			*Matchable Sample*	
	Treated	Difference	Treated	Unmatched	Matched
APD	6737/9454	29.687**	6558/9258	29.471**	3.628
		(0.653)		(0.650)	(2.048)
TTFP	2403/2659	-3.249**	2324/2563	-3.284**	-1.453
		(0.679)		(0.556)	(1.731)
Peak	4503/5708	-149.101	4378/5560	-216.896	290.839
		(395.212)		(300.663)	(1496.765)
Total	4503/5708	31649.74**	4378/5560	31183.597**	5282.528
		(4436.851)		(4209.602)	(16007.141)

Table 17: Reported SE Wells

Treatment==Misreport

	Total Sample			*Matchable Sample*	
	Treated	Difference	Treated	Difference	Matched
APD	62/3865	-0.623	62/3138	-0.209	-2.787
		(3.020)		(2.226)	(3.182)
TTFP	6/509	-2.051	6/137	-3.294	-3.5
		(2.206)		(2.511)	(8.902)
Peak	15/1020	4875.737*	15/643	4245.073*	4079.386
		(2028.071		(1839.777)	(2617.315)
Total	15/1020	86954.82*	15/643	76934.659**	64749.458
		(34259.91)		(21969.703)	(42369.446)

Table 18: Mapped Unified Wells

Treatment==Misreport

	Total Sample		*Matchable Sample*		
	Treated	Difference	Treated	Difference	Matched
APD	62/2779	-10.928**	62/2394	-11.574**	-3.100
		(3.055)		(3.617)	(3.727)
TTFP	6/262	-3.277	0/37	-2.743	.
		(2.270)		(2.329)	.
Peak	15/1220	2586.142	15/937	1725.568	-867.162
		(2052.183)		(3793.052)	(5511.597)
Total	15/1220	67759.78*	15/937	61592.226	-63666.054
		(34416.15)		(40030.315)	(80198.412)

Table 19: Mapped SE Wells

Treatment==Misreport

	Full Sample		*Matchable Sample*		
	Treated	Difference	Treated	Unmatched	Matched
APD	6737/10540	39.992**	6628/10320	39.406**	9.390**
		(0.463)		(0.520)	(1.485)
TTFP	2403/2906	-2.023**	2250/2735	-2.149**	-2.719
		(0.421)		(0.404)	(1.548)
Peak	4503/5508	2140.494**	4352/5323	2220.970**	-127.625
		(240.434)		(262.509)	(729.992)
Total	4503/5508	50844.78**	4352/5323	50274.885**	3438.576
		(2992.588)		(4137.049)	(8988.084)

Table 20: Misreporting Regression Results

	Reported		*Mapped*	
Time Measures	Split	Misreport	Split	Misreport
APD	-7.6387**	10.318**	-6.1170**	17.181**
	(0.4452)	(0.4480)	(0.4440)	(0.3847)
APD to Production	1.1655	-3.0147**	1.1748	-4.2188**
	(0.6388)	(0.5515)	(0.6465)	(0.4620)
Product Measures				
Maximum Gas	-485.68	-1126.0*	-446.62	-649.29
	(567.97)	(494.40)	(575.40)	(417.01)
Cumulative Gas	15305**	12589**	-12625	1511000
	(4423.5)	(3901.4)	(22743)	(862335)

Table 21: Misreporting Regressions Results with Propensity Score

	Reported		*Mapped*	
Time Measures	Split	Misreport	Split	Misreport
APD	-19.422**	14.348**	9.7257**	-5.2249*
	(1.6782)	(0.3592)	(1.8010)	(2.1265)
APD to Production	3.9367*	-3.5443**	-8.9449**	-1.4173
	(1.9960)	(0.3958)	(1.9634)	(3.2837)
Product Measures				
Maximum Gas	-4711.4**	-713.12*	-2427.8	-2601.7
	(1758.7)	(353.90)	(1768.5)	(2945.5)
Cumulative Gas	-1874.6	3436.3	31856*	22099
	(14001)	(2825.9)	(13804)	(22978)

Figure 1: Map of Sample Wells

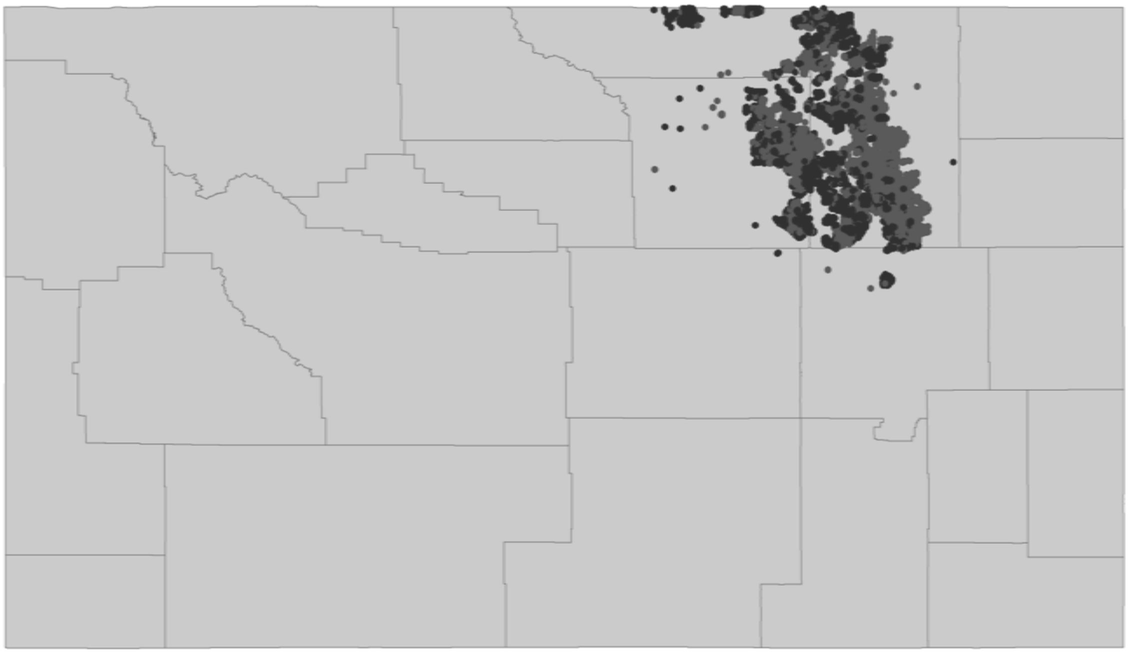


Figure 2A: Distribution of Propensity Scores for Reported Split Estate

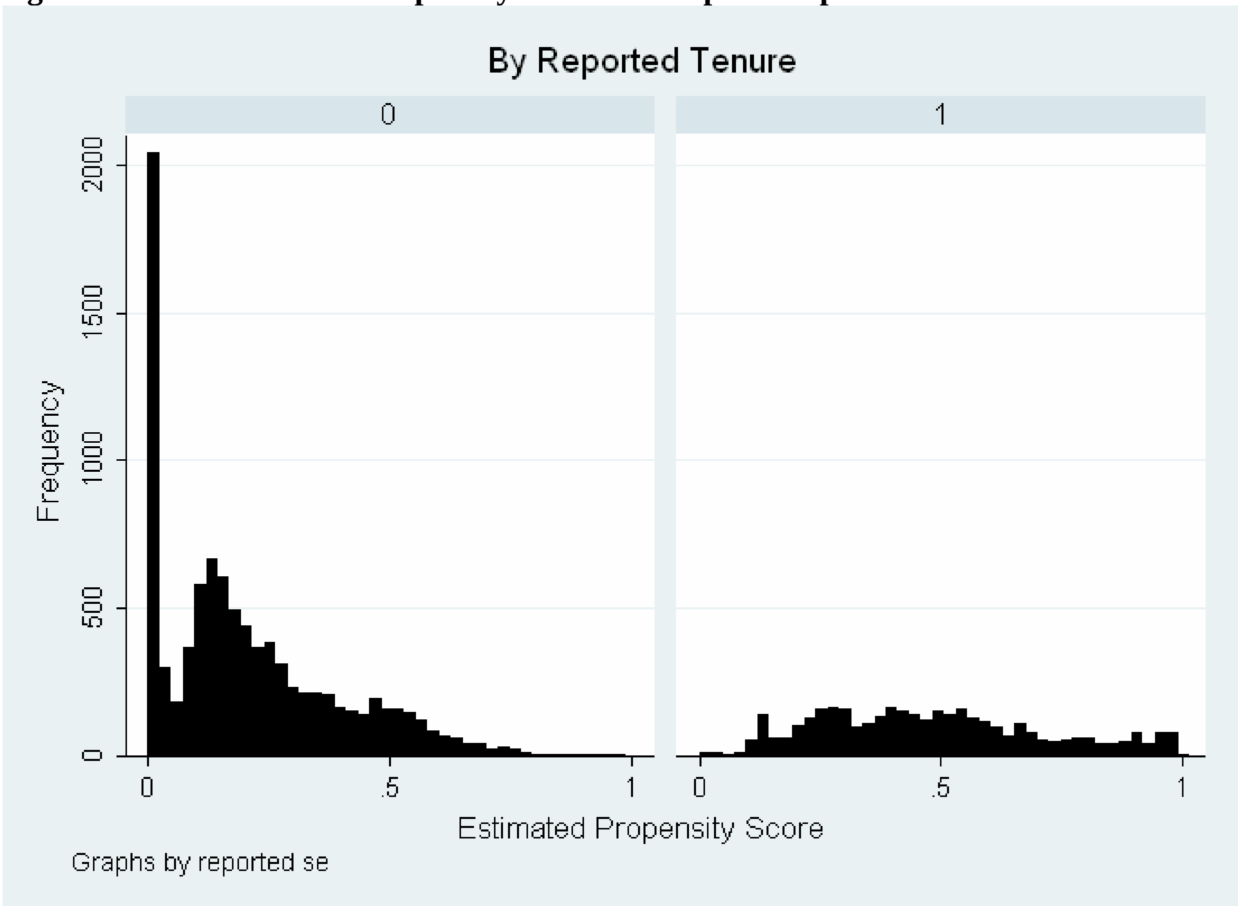
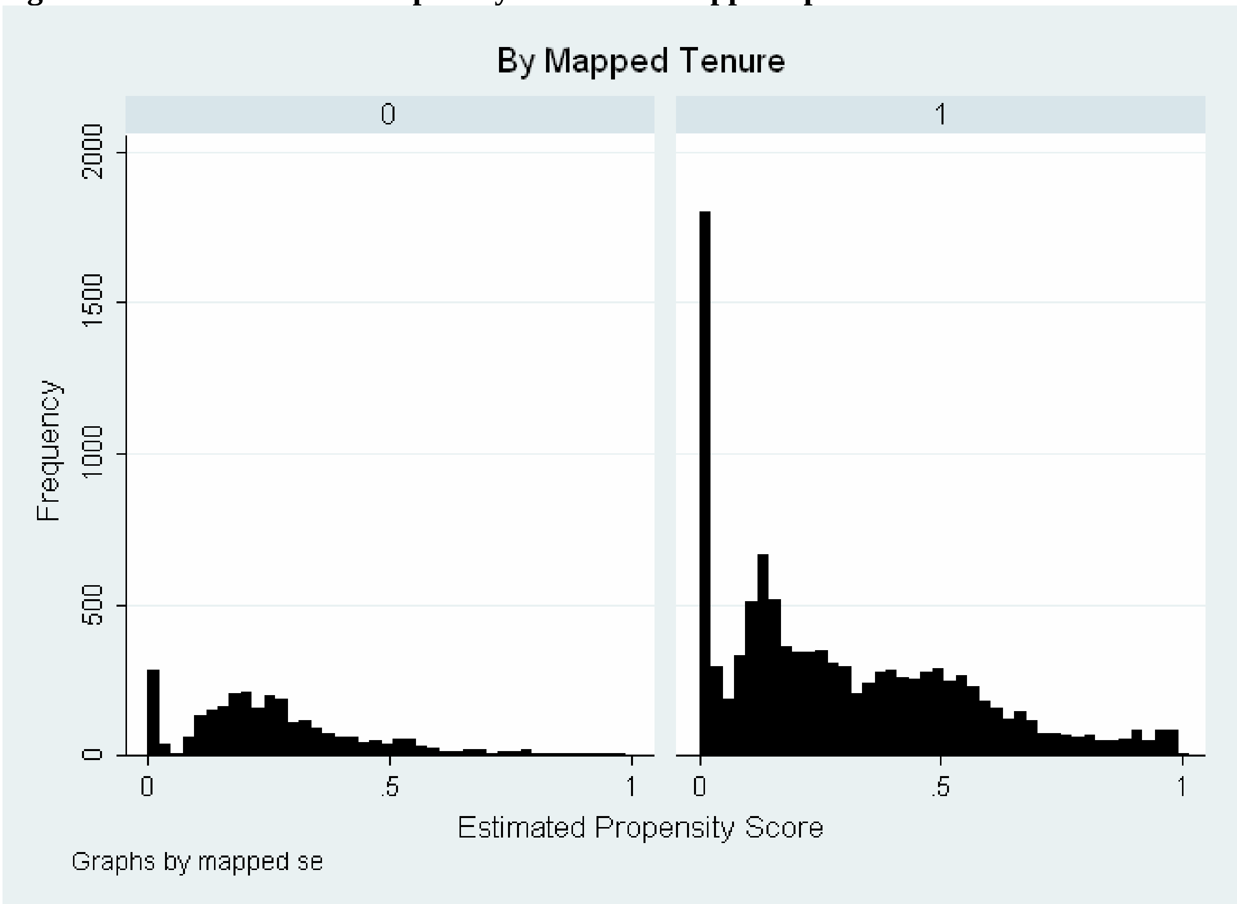


Figure 2B: Distribution of Propensity Scores for Mapped Split Estate



Appendix 1: Sensitivity Tests for Bandwidth Choice in Matching Results

Table A1.1: Reported Tenure, Bandwidth=0.1

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	-30.983**	-11.169**	9350	3829	13179
(Months)	(0.539)	(0.782)			
APD to Production	1.843**	1.154	2486	501	2987
(Months)	(0.401)	(0.667)			
Product Measures					
Maximum Gas	-2037.902**	-479.776	5509	1001	6510
(MCF/Month)	(303.107)	(441.433)			
Cumulative Gas	-42012.440**	-13365.010*	5509	1001	6510
(MCF)	(4188.714)	(5936.133)			

Table A1.2: Mapped Tenure, Bandwidth=0.1

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	15.583**	8.353**	2798	10366	13164
	(0.658)	(1.050)			
APD to Production	-2.953**	-1.022	256	2828	3084
	(0.545)	(1.252)			
Product Measures					
Maximum Gas	-632.839*	809.407	1226	5411	6637
	(281.595)	(836.127)			
Cumulative Gas	20265.536**	16743.129	1226	5411	6637
	(3941.377)	(9206.697)			

Table A1.3: Reported Tenure, Bandwidth=0.01

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	-30.983**	-10.368**	9350	3829	13179
(Months)	(0.539)	(0.911)			
APD to Production	1.843**	1.347	2486	501	2987
(Months)	(0.401)	(0.776)			
Product Measures					
Maximum Gas	-2037.902**	-354.962	5509	1001	6510
(MCF/Month)	(303.107)	(477.262)			
Cumulative Gas	-42012.440**	7090.364	5509	1001	6510
(MCF)	(4188.714)	(6937.122)			

Table A1.4: Mapped Tenure, Bandwidth=0.01

	Unmatched Difference	Matched Difference	Control	Treated	Total
Time Measures					
APD	15.583**	6.696**	2798	10366	13164
	(0.658)	(1.533)			
APD to Production	-2.953**	-1.060	256	2828	3084
	(0.545)	(2.062)			
Product Measures					
Maximum Gas	-632.839*	-365.100	1226	5411	6637
	(281.595)	(1222.908)			
Cumulative Gas	20265.536**	-12779.589	1226	5411	6637
	(3941.377)	(13714.522)			

Appendix 2: Matching Results for Misreporting, Bandwidth=0.1

Table A2.1: Correct Wells Only

Treatment==Split

	Total Sample			*Matchable Sample*	
	Treated	Difference	Treated	Difference	Matched
APD	3803/6520	10.305**	3573/6272	-10.089**	-3.537*
		(0.610)		(0.572)	(1.642)
TTFP	503/759	1.227	474/693	-0.469	3.108
		(0.766)		(0.742)	(3.559)
Peak	1005/2210	2289.595**	963/2101	-2293.021**	1237.162
		(433.370)		(477.390)	(2576.659)
Total	1005/2210	19195.05**	963/2101	-18218.085**	10668.094
		(4664.307)		(5095.049)	(19878.946)

Table A2.2: Misreported Wells Only

Treatment==Reported Unified, Mapped Split

	Total Sample		*Matchable Sample*		
	Treated	Difference	Treated	Difference	Matched
APD	6737/6799	-40.615**	5656/5717	40.993**	-3.734
		(3.029)		(3.843)	(12.563)
TTFP	2403/2409	-0.281	571/577	1.432	-1.068
		(2.178)		(3.280)	.
Peak	4503/4518	2735.244	2861/2876	-1944.368	3802.177
		(2020.261)		(2246.659)	(5601.703)
Total	4503/4518	36110.04	2861/2876	-25698.538	58303.023
		(34229.69)		(35217.218)	(106527.057)

Table A2.3: Reported Unified Wells

Treatment==Misreport

	Total Sample		*Matchable Sample*		
	Treated	Difference	Treated	Unmatched	Matched
APD	6737/9454	-29.687**	6558/9258	29.471**	8.168**
		(0.653)		(0.650)	(3.115)
TTFP	2403/2659	3.249**	2324/2563	-3.284**	-1.630
		(0.679)		(0.556)	(2.431)
Peak	4503/5708	149.101	4378/5560	-216.896	390.960
		(395.212)		(300.663)	(1844.554)
Total	4503/5708	-31649.74**	4378/5560	31183.597**	14600.180
		(4436.851)		(4209.602)	(21324.126)

Table A2.4: Reported Split Wells

Treatment==Misreport

	Total Sample		*Matchable Sample*		
	Treated	Difference	Treated	Difference	Matched
APD	62/3865	0.623	62/3138	-0.209	-2.000
		(3.020)		(2.226)	(4.004)
TTFP	6/509	2.051	6/137	-3.294	-0.500
		(2.206)		(2.511)	(3.146)
Peak	15/1020	-4875.737*	15/643	4245.073*	4116.267
		(2028.071		(1839.777)	(2785.829)
Total	15/1020	-86954.82*	15/643	76934.659**	63302.733
		(34259.91)		(21969.703)	(44577.610)

Table A2.5: Mapped Unified Wells

Treatment==Misreport

	Total Sample			*Matchable Sample*	
	Treated	Difference	Treated	Difference	Matched
APD	62/2779	10.928**	62/2394	-11.574**	-11.339*
		(3.055)		(3.617)	(5.438)
TTFP	6/262	3.277	6/43	-2.743	-2.500
		(2.270)		(2.329)	.
Peak	15/1220	-2586.142	15/937	1725.568	-882.400
		(2052.183)		(3793.052)	(7071.039)
Total	15/1220	-67759.78*	15/937	61592.226	-93494.467
		(34416.15)		(40030.315)	(162426.407)

Table A2.6: Mapped Split Wells

Treatment==Misreport

	Full Sample			*Matchable Sample*	
	Treated	Difference	Treated	Unmatched	Matched
APD	6737/10540	-39.992**	6628/10320	39.406**	17.017**
		(0.463)		(0.520)	(2.196)
TTFP	2403/2906	2.023**	2250/2735	-2.149**	-5.155**
		(0.421)		(0.404)	(1.688)
Peak	4503/5508	-2140.494**	4352/5323	2220.970**	1515.282
		(240.434)		(262.509)	(847.424)
Total	4503/5508	-50844.78**	4352/5323	50274.885**	40422.931**
		(2992.588)		(4137.049)	(10295.169)

Essay 3: The Role of Split Estate in Environmental Performance of Coalbed Methane Development

1. Introduction

Recent expansion of oil and especially natural gas development in the western states has raised issues about control over environmental impacts. In particular, production from severed minerals, or “split estate,” has been a concern in the states that have seen the most development. Environmental service streams are an essential input in surface production, which is typically agriculture in the rural West, but not necessarily in mineral production. A conflict results when the surface and minerals are owned separately. Joint production from unified ownership is expected to yield the efficient amount of pollution if all effects are local. In the absence of perfect information and costless contracting, divided ownership is unlikely to lead to the same outcome. On-site impacts are only part of the total environmental effects; downstream third parties also bear the consequences of water disposal. It is not clear if there is correlation between direct (on-site) and indirect (third-party) impacts; they may be substitutes or complements. Given that split and unified estates are spatially interspersed, differences in environmental outcomes by tenure may be magnified across the landscape.

Concerns about split estate are not new but have gained a fresh urgency in recent years. Historically the mineral estate has enjoyed legal predominance. In 2005 Wyoming revisited its statutes pertaining to the relationship and responsibility of the mineral developer to a surface owner who does not also own the minerals.

Two years later both Colorado and New Mexico followed suit.[49] Despite this action, the economic effects of split estate as an institutional structure are only partially understood. Uncertainty about environmental impacts from new extraction technologies makes incompletely-defined property rights a problem. At the same time, substantial attention has been dedicated to the environmental impacts of development. With little baseline data to work from, few indisputable conclusions about the extent of environmental damage have arisen, but concerns over the disposal of produced water have been among the leading reasons for condemnation of increased natural gas development (Darin (2001), Darin and Beatie (2002)). This paper connects the effects of tenure to the incidence and severity of water discharge violations for coalbed methane (CBM) wells in Wyoming. For reasons of identification, attention is focused on federal minerals—comparing private surface with federal minerals (split estate) to control of both surface and minerals by the federal government.

So-called "unconventional" extraction technologies have achieved a preeminent status during the recent natural gas boom.[50] Among these, coalbed methane represents the most dramatic departure from traditional extraction technology because of the large amount of produced water.[51] Water or steam is often injected to enhance traditional recovery by maintaining geological drive. In some

---

[49] See: Wyoming Surface Owner Accommodation Act of 2005 (W.S. 30-5-401); New Mexico Surface Owner's Protection Act of 2007 (N.M.S.A. 70-12); Colorado Surface Owner Protection Act of 2007 (C.S. 34-60-127). Montana, North Dakota, and Utah have debated revising their statutes in recent years as well. In addition, the Bureau of Land Management (BLM), which administers federal onshore energy leasing, conducted a nationwide review of its policies in 2006 in accordance with Section 1835 of the Energy Policy Act of 2005.

[50] Bohi (1998) outlines the technological advances that have allowed unconventional resources to be widely exploited.

[51] Appendix 2 provides a complete overview of the production process, but pertinent aspects of water disposal are discussed below.

cases, the lack of available water is a constraint on production.[52] In order to produce coalbed methane, subsurface coalbeds must be dewatered, thereby releasing hydrostatic pressure that holds gas molecules in the microfractures of coal. Produced water is brought to the surface and cannot be put back into its source formation. If the water were to be pumped back into the coal, any remaining methane gas would be trapped by the hydrostatic pressure. Produced water is often disposed of on the surface because alternative subsurface formations of sufficient size are not always available to reinject water. This problem has been most pronounced in northeastern Wyoming where expansive coalbeds hold large amounts of gas and water beneath three major river drainages: the Belle Fourche, Cheyenne, and Powder River. According to USGS (2000), 400 barrels per day per well is considered average water production in this region; Boysen et al. (2002) estimate that the Wyoming portion of the Powder River Basin produced 375 million gallons of CBM water in 2000. Extensive development since 2000 has necessitated the disposal of billions of gallons of water, much by direct surface discharge. Compliance of these discharges to the pertinent environmental regulations is the focus of this paper.

Three motivations drive this research. First, it is the third part of an investigation of the economic role of split estate; the first two examined the impact of severed property rights in leasing and gas production, respectively. Second, this work is a first estimate of how environmental compliance varies with property rights in energy production. Since statutory environmental requirements are the same but incentives differ across tenures, identifying performance differences gives insight as

[52] This is true in other types of unconventional extraction as well. For example, see Gaudet et. al (2006) on the topic of water use for tar sand mining.

to how varying ownership structures might be exploited to further environmental stewardship. Split estate has been politically contentious in states where coalbed gas is being developed, but there is no information regarding whether split estate affects environmental outcomes. Divided ownership with imperfectly-defined property rights is likely to bear on environmental impacts in other settings unrelated to energy production. Third, this paper connects to a large existing literature on environmental compliance that is not integrated with the literature pertaining to nonrenewable resource extraction despite obvious impacts of mineral extraction on environmental quality.

Using a unique dataset linking individual wells to their (often shared) discharge permits, I find that split estate wells are covered by permits with a somewhat larger number of violations, but that the severity of the violations is not statistically different from unified wells that also have violations. These results are consistent at both the permit and well level. This suggests that operations on split estate are more apt, whether by intent or neglect, to be found in violation of the existing statutes, given that the permit is in violation. However, the likely seriousness of the violations is no different on split estate, ruling out any suggestion that firms are wildly irresponsible on split estate. The unconditional incidence of violations is about one percentage point higher for wells on federal minerals than those on private or state minerals.

The paper proceeds as follows. The next section provides background on CBM technology and the process of permitting and enforcing direct discharge sites. It also explains how divided ownership bears on compliance with water discharge statutes for CBM wells in Wyoming. The third section discusses the provenance of the data with explanation of the dependent variables used to measure the extent of environmental compliance. The fourth section introduces the empirical methodology and presents the results. A discussion concludes.

2. Split Estate and Environmental Performance of CBM Wells

2.1 Background and Technology of CBM

Hydrostatic pressure traps methane produced during the formation of coal in the microfractures of coalbeds. Subterranean coal miners have been aware of this for centuries, with sometimes tragic results. Much conventional natural gas originated in coal; without water holding it in place the gas migrated into adjacent formations before it was trapped by an impermeable geologic structure. Vast bituminous coal deposits in the West are located too deep for surface mining to be profitable, but at depths considered quite shallow among gas drillers.[53] These bituminous coals have sufficient porosity to have high gas content and allow gas to flow through them. By drilling a wellbore into the coal and pumping the water out, the gas is volatilized and can be collected and marketed.[54] This technological realization underlies the exploitation of CBM. But the water must be brought to the surface in order to get the gas. The two are typically separated at the wellhead on the surface.

[53] Whereas some natural gas wells in Wyoming are deeper than 15,000 feet, the mean depth of CBM wells in northeastern Wyoming is 1073 feet.
[54] Several sources give more detailed accounts of CBM technology: only the most pertinent aspects are discussed here. See Bryner (2003), Darin (2002), Darin and Beatie (2001), Wheaton and Donato (2004), and references therein.

The problem is: what to do with the water? Where the water is potable, this is not a problem since fresh water is always in demand. Frequently the water in coalbeds is not potable, as Rice et al. (2000) detail.[55] In those cases, disposal potentially affects surface water and land uses. Some effects are limited to the immediate vicinity of a well. Direct discharge to the surface when contaminated water sickens livestock is one example. However, if saline produced water is discharged into rivers from which downstream irrigators withdraw, the potential number of parties harmed by the externality is high. For example, even though western water law allows downstream irrigators to own specific quantities of water, there are no claims on the quality of the water they receive. In fact, in some cases, CBM outfalls have increased stream flows while decreasing water quality. Both results might be unwelcome to an irrigator.

2.2 Water Disposal

Three main techniques for water disposal are used extensively. The first is reinjection into a different subsurface stratum than the coal being exploited. Water can be reinjected simply in order to be rid of it, but more commonly it is put to a beneficial use by aiding recovery of other resources. While this technique has worked well for operators in New Mexico, where numerous depleted petroleum fields are near CBM wells, it has not been an option for most operators in Wyoming

[55] An extensive additional technical bibliography on the properties of water produced by CBM wells is available at: http://deq.state.wy.us/wqd/WYPDES_Permitting/WYPDES_cbm/Pages/CBM_Watershed_Permitting/Bibliography/CBMBibliography.asp. Last accessed: 3 December, 2008.

because there are no available formations.[56] Unless oil or gas has previously been pumped out of the ground, it is unlikely that an operator can find a substantial structure to accommodate water disposal.

The second water disposal tactic is evaporation. In some cases firms have tried to use spray guns or misters that evaporate water in arid climates. More commonly water is collected in specially-built earthen evaporation pits.[57] Some of these pits are lined, preventing leaching into shallow aquifers that may be used for potable water. Others are unlined and have been an object of concern.

Direct discharge, or emitting effluent on the surface, is the third option. Three main categories exist. The first can be characterized as beneficial use.[58] In Montana, produced water is used for dust control at nearby surface coal mines. In Wyoming, produced water is commonly used for watering livestock or even irrigation. Where feasible, these sorts of productive uses have been very popular with surface users, even severed surface owners.[59] A small percentage of water is used in this way, perhaps because additional beneficial use permits are required in order to put the water to a second beneficial use. The second is direct surface discharge, where water spills out on the ground, often in an intermittent watercourse. Sometimes these discharges find their way into surface water, often during a large rainstorm or the like.

[56] The exception to this is Anadarko Petroleum, which built a 48-mile, $50 million pipeline for produced water. The water is transported to Midwest, WY, where a depleted petroleum formation is used to dispose of the water.

[57] An interesting side effect of evaporation pits is the increase in mosquito habitat, which increases mosquito populations and potentially transmission of West Nile virus. The impact on bird populations, notably sage grouse, has been a topic of recent research (Doherty et al. (2008)).

[58] As a state with appropriative water law, one necessary precondition for widespread CBM development was for the State Engineer of Wyoming to declare the extraction and disposal of produced water as a "beneficial use" of water. Since it is an essential output of the CBM production process, it does fit the letter of the law. However, in this context "beneficial use" is used in a more traditional sense.

[59] A large-scale pilot project using produced water to irrigate in Montana has recently been concluded after five years of research. More details are available at www.tongueriverampp.com.

The third group is direct discharge into a natural watercourse. Obviously water must be potable or near potable in order for this to even be an option, but in large parts of the PRB produced water is sufficiently clean to allow outfalls straight into surface water. Both of the last two categories are covered by the discharge permits studied here.

2.3 Permitting, Monitoring, and Enforcement

Measuring the extent and severity of water pollution is a science unto itself and the development of CBM has spawned a side industry of specialist firms that handle permitting, monitoring, and disposing of produced water. Point-source discharges of water are regulated under the National Point Discharge Elimination System (NPDES), with administration and enforcement relegated to states. In Wyoming, the Department of Environmental Quality (WYDEQ) is responsible for granting, administering, and enforcing permits. The rest of this section will quickly outline the process of getting a permit—and getting a violation.

An operator must obtain multiple permits during the planning process: the two most important are a drilling permit from the Wyoming Oil and Gas Conservation Commission (WOGCC) and a water discharge permit from the WYDEQ (in the event the operator plans to dispose of water by surface discharge). On federal minerals, an operator must submit a plan of development to the local field office of the Bureau of Land Management (BLM). In addition, on split estate a developer must either reach a surface use agreement with the surface owner or post a bond covering damages that allows entry without an explicit agreement. Operators submit a WYPDES permit application detailing the location of planned discharge points, or outfalls. Typically this permit application is made concurrent with applications for well and other permits. Consequently, the initial application often does not include reference to specific wells. Permit revisions are common, allowing developers to add or remove specific wells from the permit. However, records of these changes are not complete, which has implications for connecting specific wells to discharge permits. This problem is discussed in the data section below.

One reason for the imperfect record-keeping is that operators must deal with no less than three state agencies in order to make direct surface discharges. First, the well must be permitted by the WOGCC. Then, the operator must appropriate the groundwater for beneficial use through the State Engineer's Office. If surface discharge is the preferred disposal method, then the operator must also obtain a WYPDES permit. Denial of a thorough permit application is very rare, but delays in obtaining the permit are routine. The cost of a WYPDES permit is $100.

After permits and access are in place, the developer can construct and complete wells. Because most CBM wells are relatively shallow, they can be drilled quickly. Pipelines to collect gas and water must be laid and connected to each well. Because there are increasing returns to spatial scale in dewatering subsurface aquifers, developers typically proceed with groups of wells in an approximate grid pattern. Several wells may be covered under a single discharge permit, with local collection pipelines conveying water from wellheads to outfalls. Once wells are completed and water begins to be discharged, an initial monitoring report is filed, indicating to the WYDEQ that water is being discharged. The initial monitoring report is followed by Discharge Monitoring Reports (DMRs), which must be filed quarterly. Many operators retain specialized subcontractors to monitor outfalls and file discharge reports with the WYDEQ.

In the event an outfall exceeds one of the water quality standards (an event somewhat awkwardly termed an "exceedance"), WYDEQ gives the operator a formal notice and a time window to correct the situation. Fields staff may visit an outfall to sample the discharged water and determine if it is in compliance.[60] Staff members sometimes make recommendations to operators, which are recorded as comments on the permit. If uncorrected, the exceedance is recorded as a formal letter of violation. More serious transgressions and unremediated letters of violation lead to notices of violation. The WYDEQ can recommend a penalty for serious violations, and as a last recourse revoke the WYPDES permit. The violation data include all types of records ranging from initial monitoring violations to notices of violation to case in which penalty is recommended.

In light of the rapid proliferation of CBM wells around Wyoming, the WYDEQ was overwhelmed by the volume of permit applications and the ensuing enforcement workload. While developers are able to subcontract much of their permit compliance work to water quality specialists, the DEQ had to glean additional appropriations from the state legislature to expand its staff. Staff size has doubled since 2002 and a special Coalbed Methane Division has been formed to handle the WYPDES permitting and enforcement for CBM wells. However, delays in processing both new and revised WYPDES permits are still months long, far longer

[60] During the initial period covered by the data used here, WYDEQ had one field inspector for all CBM wells in the state. That number has since increased to four.

than the days or weeks needed by WOGCC to turn drilling permit applications around.

One concern that this raises for the empirical study is that because WYDEQ employees recognize their personnel constraints, they might allocate enforcement effort in some way that is correlated with tenure. Discussion with WYDEQ staff suggests that this is not the case. The maintained assumption is that regulators enforce the statutes without regard to tenure.

2.4 Why Tenure Matters

If all effects of discharging contaminated produced water are restricted to the same parcel where the well (and presumably the outfall) is located, bargaining is likely to resolve the problems that are created by the need to dispose of produced water. On split estate mineral developers must negotiate for surface access and local damages are likely to be compensated.[61] Discharge into surface water or even off-channel discharges are likely to impose externalities on downstream parties.

Mokyr (2002) suggests that property rights are not to blame for environmental hazards, instead implicating "insufficient information due to the novelty of new techniques and the complexity of technological 'system' [*sic*] into which they are introduced." Adoption of CBM technology has created information problems for mineral developers and surface owners alike, not the least of which is understanding how to best dispose of produced water. While mineral developers may have more

[61] Negotiated surface use agreements are the norm. The accommodation doctrine allows developers who are unable to reach an agreement with the surface owner to post a bond covering damages. On federal minerals, this bond covers only damages to structures or crops. Since contaminated water potentially affects other dimensions of the surface property such as native crops, wildlife, or livestock, it is possible that bonds will not adequately protect the surface user.

complete knowledge about techniques, surface owners might have a better understanding of the complex ecological technology. Severed ownership per se may not be the problem, but the prevalence of split ownership in the context of new and uncertain technology allows the possibility that modest transaction costs might prevent full integration of knowledge about the surface and subsurface service streams with negative implications for the level of externalities that persist. Estimating the environmental effect of split estate in CBM development is essentially accounting for the resilience of the institutional structure in a dynamic context. To the extent that split estate is a significant cause of environmental impacts, information asymmetries are a proximate cause.

Because the pertinent environmental regulations do not differ, one might expect there to be little difference in how water is discharged from wells on split and unified estates. However, a split estate owner stands to make little financial gain from development and is often engaged in agricultural activity on the surface, so exposure to the risk of water contamination is unwelcome. Two factors suggest that environmental performance on split estate might be better than on unified. First, the surface owner may monitor more closely than a unified owner (especially the BLM) since contamination of irrigation water or the surface may directly harm agricultural production. Lacking the positive incentive that a unified landowner faces in the form of a royalty payment, a severed surface owner may be a closer monitor. Many of the effects of water discharge may be hard to evaluate, leading to the problem of hidden action by the developer. An agricultural producer is likely to be intimately familiar with pre-existing conditions and therefore able to perceive even small changes in water quality.[62] The comparison group in the study, federal unified estate, does not enjoy this advantage. Even at the field office level, BLM staff are rotated with such frequency that few have an opportunity to develop the sort of thorough understanding of a particular tract the way an agricultural producer does.

The second advantage that surface owners enjoy is that development has largely been later in time on split estate.[63] Given that water discharge problems have attracted unwanted scrutiny and attention to gas developers, increasing awareness and improving technical mitigation procedures have likely reduced the incidence of violations. Later timing of development on split estate may be indicative of more care by operators and help surface owners. The hypothesis that discharge violations have decreased over time is testable.

Working in the opposite direction, split estate suffers two distinct disadvantages as compared to unified estate. The first is that the unified owner clearly has an incentive to maximize the joint products of a parcel. This means considering the reciprocal costs of competing uses of a parcel. It is possible that optimal use may entail a corner solution in which mineral extraction proceeds and any alternative use is foregone. In either case an owner will have to solve the agency problem via contracting with a specialized energy developer. In the event that the owner is a specialized developer, then the likelihood of a corner solution would appear to be increased.

---

[62] However, many surface owners lack the resources to bring legal claims against mineral developers, since conclusive evidence is very expensive to collect.

[63] Since WYDEQ does not record the tenure of wells in permit applications (or sometimes even which wells are covered by a particular permit), in order to determine the tenure of wells, the WYPDES data were merged with well-level data from the WOGCC. This well-level data has a known divergence of reported tenure from the tenures that appear when mapped. Accordingly, results are presented for each of these two groups.

One implication for the specific empirical setting that is considered here is that the BLM may be more sensitive to impacts on unified estates, where the BLM has authority for surface use, than it is on split estate, when maximizing the value of the mineral estate within regulatory bounds is its only apparent objective. The higher incidence of restrictive leasing stipulations that the BLM puts on leases with unified tenures is evidence of this sensitivity.

The second stylized fact that suggests that surface owners are at a significant disadvantage is the information asymmetry about the likely effects of development between energy developers and landowners without substantial geological and legal expertise. Operators have a much clearer idea about the likely course and impacts of development than surface owners do. A surface owner may have little idea about what the likely effects of development may be on their surface use ex ante, let alone be able to identify potential hazards before a violation occurs.[64] In contrast, the BLM, even at the field office level, is likely to have both mineral and surface specialists who can discuss likely impacts and require a development plan that protects the surface. Corroborating evidence of this is the more liberal use of leasing stipulations that restrict surface impacts on leases comprised of unified estate.

3. Data

3.1 Provenance

Two main sources of data are integrated in order to make this study. The first is well-level data from the WOGCC that includes all CBM wells in the state. A

[64] However, as mentioned above, a surface owner may be uniquely able to perceive changes on their land.

record enters the data when a developer applies for a drilling permit. If the well is actually constructed and ultimately produces gas, descriptive characteristics are augmented by monthly production records for both gas and water. However, these data only include operator reports of how much water was produced, with no implication for the quality of the water and likely downstream impacts or the compliance with statutes in force. Well-level data on the usage of water disposal technology does not exist. Since volume is not necessarily correlated with the probability of an infraction, the volume of produced water is not informative in itself.

Data on WYPDES permit violations during the period up to and including November 1, 2006, were obtained directly from the WYDEQ. In order to match permits to wells, the permits had to be inspected and the well numbers (where available) recorded. Matching wells to permits proved more difficult than anticipated, with the result that only about 5 percent of wells have been directly tied to specific WYPDES permits. This is hardly surprising since alternative water disposal methods are available; evaporation (which does not require a WYPDES permit) is a popular option for CBM operators. While these are good reasons to expect less than full coverage, I did hope for more complete overlap (and may ultimately be able to achieve it). Surface discharge has been the least-cost water disposal option for most operators, especially in the Powder River Basin (Boysen et al. (2002)).

The matching of WYPDES permits and well numbers proved difficult because the regulatory responsibility of the agencies does not overlap. As a permitting and enforcement agency, WYDEQ is not particularly interested in the CBM wells themselves, instead allowing WOGCC to oversee them. Conversely, WOGCC is not especially concerned with discharge outfalls.[65] Despite the mechanical difficulties, the integration of these two data sources is unique, allowing construction of a sample of moderate size.

Table 1 presents descriptive statistics for all CBM wells, showing the relative frequency of violations. Only a small percentage of wells are linked to permit violations. In part this is because not all wells use a WYPDES permit, but also because the poor alignment of the permit and well data. A higher percentage of wells on federal minerals have violations.

Descriptive statistics for the 953 WYPDES permits with recorded violations for CBM operations are presented in Table 2. These data are drawn from the violation database, which unfortunately does not include data on permits that were not found in violation. Most violations are relatively minor in nature, reflecting that one permit often receives multiple initial notices. If uncorrected, these many minor conditions can compound into fewer more serious infractions.

The time profile and classification of violations is shown in Table 3. Conditional on there being violations, the median number of infractions for a single permit is 27, but the table shows that some permits have many times more. Most of the violations are relatively minor or cursory in nature, but a substantial number are more serious. (The types of violations and the ordinal severity of those violations are reported in Table 5, but the groups are shaded in Table 3.) Severities represent rank ordering assigned after discussion with WYDEQ staff. The first level of severity

[65] Operators may also be interested in obscuring the ultimate source of discharges in the event that they are found to be damaging.

represents mundane notices pertaining to performance. For example, every permit has an initial monitoring report and a compliance inspection—these only enter the data as a violation when those standard procedures discover an exceedance. The second category—letters of violation—represent a slightly more serious infraction. Since operators are often able to avoid more serious penalties at this point, letters of violation are less serious than notices of violation. The final category includes the most serious infractions for which a penalty is recommended. Also included are a group of wells under criminal investigation for discharge violations. The severity of violations corresponds both to the expected cost to a firm for complying with the violation notice and the social cost of the environmental damage involved. The investigating and enforcing officers do have some discretion in deciding what type of violation to issue, so the ordinal severities should be considered a guideline. But there is no anecdotal or objective evidence to suggest that regulators adjust violation type based on tenure.

Table 4 reports how the tenure of matched wells varies across permits with violations. Of these permits that can be linked to individual wells, the average number of wells per permit is 28. Although not reported here, anecdotal evidence suggests that this number has increased over time. One possible explanation for this is that permit application is a fixed cost and operators have sought to spread this fixed cost over more wells over time. An alternative (but not exclusive) explanation is that operators have tried to increase the volume of water attributable to each permit, thereby reducing the risk of a violation, which is usually measured in concentration levels or percentage terms. By increasing the volume, the probability that a permit will be found in violation is reduced since standards are concentration levels.

3.2 Dependent Variables

The main dependent variables used here are the total number of violations of a permit, the number of violations per well, the total severity of the violations of one permit that are reported, and the per-well severity of all violations. The absolute number of violations reveals the incidence of violations and the likely magnitude of environmental harm for each permit. Normalizing each permit by the number of wells it covers gives a truer estimate of the effect of tenure on the performance of individual wells.

The number of violations is not the only measure since a larger number of minor violations might be less harmful than fewer more serious infractions. Violations are grouped into four categories of severity as detailed in Table 5. These measures are thought to capture the essence of the water pollution problem since more violations increase the risk of a destructive episode, and the severity of the violations reflects the risk of damage. Initial monitoring report violations, administrative orders, comments, and compliance inspections are given the lowest ranking. This determination was made after reading a sample of the violation comments for each class and discussion with WYPDES staff. Letters of violation are more serious, and are given a severity ranking of 2. Letters of violation are generally preceded by a minor notice such as a comment. Notices of violation are issued if letters of violation generate no result. These are recurring violations that warrant a formal notice in the opinion of the investigating officer. The most severe violations are those for which a penalty is recommended. Also included in this category are a group of violations that the state attorney general investigated to press criminal charges against the operator.

4. Empirical Methodology and Results

4.1 Econometric Framework

A primary concern is that tenures are endogenous since firms select the location and timing of well construction and production. One possibility is that tenure is correlated with geologic formations that are more likely to give rise to violations of discharge permits, perhaps because of the aquifer chemistry of a particular formation. The maintained assumption is that the creation of property rights via homesteading laws in the late 19th and early 20th century led to a pattern of ownership that is independent of the risk of violations of water discharge standards.[66] The intermingled pattern of ownership overlies extensive coalbeds of generally homogenous geological characteristics. Therefore systematic variation in performance is attributed to differences in how operators react to the incentives on split and unified tenures. However, as noted above, the appearance of wells in the WOGCC data, or on WYPDES permits, may still be endogenous.

Choices by developers regarding when and where to drill wells and which technology to use to handle produced water are treated as simultaneous. It is possible

[66] The pertinent history of homesteading and its implications for randomized tenures is summarized in Appendix 1.

that a developer could decide when and where to drill a well and then subsequently elect a water disposal technique based on additional criteria.

A propensity score matching model is used to control for the potential endogeneity of tenure, the source of which is the selection of well sites by developers. For example, if developers know that surface owners will be hawkish monitors of water discharges, which potentially raises environmental compliance costs, they may choose to develop unified parcels instead. Propensity score matching technique compares a split estate well to unified wells that are most similar in terms of observable characteristics that developers use to select well locations. Since there is some local variation in water quality, controlling for the neighborhood that a well is in is a critical concern. Propensity score matching has received most attention in labor economics, in particular in the context of evaluating the effectiveness of training programs for workers (e.g., Dehejia and Wahba (1999) (2004), Heckman, Ichimura, and Todd (1997) (1998)). Score matching models have been used in other fields—including increasingly in environmental work (e.g., List et al. (2003), Lynch et al. (2007), Bento et al. (2008)).

Matching estimators rely on the assumption of "selection on observables" rather than parametric assumptions about unobservables. In choosing when and where to drill CBM wells, developers lack detailed information about the likelihood a specific well will lead to environmental violations. Staff geologists identify profitable formations and select locations that are expected to maximize returns. Tenure may affect profits, so ideally we would compare wells that are identical in all pertinent respects. Since numerous observable characteristics factor into firms' decisions, and some of those are continuous, constructing an appropriate counterfactual for each well runs into the “curse of dimensionality.” In order to avoid this problem, Rosenbaum and Rubin (1983) suggested calculating a scalar propensity score, or conditional probability of treatment. Wells with similar propensity scores are regarded as also similar in terms of unobservable characteristics. In order to ensure that treated (split) and control (unified) wells are in fact similar, tests are conducted to ensure that wells with similar propensity scores in fact also have similar observable characteristics. Results of these balancing tests are presented in the next subsection.

After the propensity score is calculated using a logit specification, a counterfactual is constructed for each treated (split) well by kernel-weighting the nearest control (unified) observations. An Epanechnikov kernel is used. The optimal bandwidth is selected by Silverman’s (1986) criteria.[67] For this sample the selected bandwidth is 0.035. Sensitivity analysis is performed to evaluate the impact of this choice. The average difference between each treated well and its individual counterfactual is interpreted as the average treatment effect.

4.2. Balancing Tests

Rosenbaum and Rubin (1983) laid out the theory for propensity score matching. The key assumption is conditional mean independence, which is typically checked by making sure that treated and control observations have statistically

[67] The optimal bandwidth is $1.06\sigma N^{-\frac{1}{5}}$, where σ is the standard deviation of the propensity score and N is the sample size. Tests for the sensitivity of this choice are performed at bandwidths of 0.1 and 0.01.

indistinguishable value of the main independent variables of interest across the common support of the propensity score. The propensity score equation includes observable characteristics of wells, including physical location, year developed, and formation, among others. Additional higher-order terms in these variables and interaction terms were included in the propensity score specification, but these terms were not subjected to balancing tests.

Figure 1 depicts the distribution of propensity scores, which are also reported in Table 6A. Common support is generally not a problem and the scores are spread out across the entire unit interval. The balancing property is not satisfied at conventional levels for all of the primary observable characteristics. The failures of the mean independence property are reported in Table 6B. One possible explanation for this is the high degree of collinearity between several of the geographic variables. While statistically significant, the within-block differences are not always economically meaningful. The balancing problem reflects the imperfect randomization of tenures in some places. The overlap between split and unified wells in terms of propensity scores and observable characteristics reflects how even imperfect randomization creates an effective natural experiment.

4.3 Results of Propensity Score Matching Model

Table 7 reports results for the well-level matching model. The upper section of the table uses the reported tenure from the well data as the determinant of treatment. Although the unmatched differences are not statistically significant, after controlling for the endogeneity of tenure by matching, we find that there are about 10 more violations associated with each permit for split estate wells. Given a median number of violations for permits with at least one of 27, an additional 10 infractions is a substantial as well as a significant difference. When the number of wells matched to each permit is taken into account, the number of violations is still about 2.1 violations higher after matching, versus an unmatched difference of 1 violation.

Although the matching model reveals a higher incidence of violations on split estate, the severity of the violations is not significantly different by tenure. The unmatched severity-weighted difference for each permit is 181, but after matching is not different from zero. Likewise, on a per well basis, the severity-weighted difference is almost 44, while not different from zero after matching. Due to the reduction of sample size by excluding wells without any observations, six split wells were excluded for lack of common support.

The lower section of the table uses the mapped tenure of well locations as the determinant of treatment. Using this definition, the unmatched differences are statistically significant, suggesting that split estate is associated with almost 10 more permit violations. After controlling for the endogeneity of tenure by matching, this difference increases to about 16 and remains significant. This estimate is somewhat larger than the difference of 10 from the reported split estate. This difference is surprising since the change in the definition of treatment substantially changes the composition of the sample, but the sign and magnitude of the effect is roughly constant. When the number of wells matched to each permit is taken into account, the number of violations is still about 3.4 violations higher after matching, indistinguishable from the unmatched difference.

As with the reported treatment, the severity of the violations is not significant in the matched model. The unmatched severity-weighted difference for each permit is also not significant. On a per well basis, the severity-weighted unmatched difference is almost 57, while not different from zero after matching. The common support problem was more pronounced with the mapped definition, requiring the exclusion of 397 of 450 split estate wells.

Table 8 presents results using a wider bandwidth of 0.1. In general, a wider bandwidth should give more efficient estimates but is more susceptible to bias. This prediction is borne out as the estimates are slightly attenuated toward zero and the standard errors are smaller. However, the basic results are upheld—the number of violations differs in aggregate or on a per well basis, while there is no effect in terms of severity.

Table 9 reports matching results using a narrower bandwidth of 0.01. In general, this narrower bandwidth sacrifices efficiency to minimize bias. The main results are unchanged—a difference in incidence but not severity of violations by tenure. The point estimates in this case a virtually indistinguishable from those in Table 7 using the optimal bandwidth of 0.035.

4.4 Results of Baseline Linear Regression Model

Linear regressions that do not control for the endogeneity of tenure are a useful comparison for the matching model. These results establish a baseline estimate and are reported in Table 10. The first column reports the results of a linear model with fixed effects for reservoir and county using the reported tenure of wells.

The point estimates of 11.4 more violations per permit and 2.4 more violations per well for reported split estate conform reasonably well to the matching estimates of about 10 more violations per permit and 2.1 more per well. Like the matching models, the linear regressions do not indicate a significant impact of tenure on the severity of violations.

The mapped definition of split estate gives wildly different and insignificant results for both incidence and severity. This may indicate a specification problem in the linear regressions.

5. Discussion

These results suggest that tenure plays a role in explaining differential environmental performance of CBM wells, at least as measured by incidence of violations of a WYPDES permit. The unmatched results suggest that although there are not significant differences in the number of violations per permit, the severity of the violations is higher on split estate. However, after controlling for the endogeneity of tenure, I find that the number of violation is slightly but significantly higher on split estate. For reported split estate, the estimates range from 9.6 to 10.1 more violations per permit or 2 more violations per well. Mapping wells yields slightly higher estimates, between 15.1 to 16.3 more violations per permit and 3.2 to 3.5 more violations per well. Linear estimates are comparable for reported split estate but significantly different for mapped. The severity of violations is not significantly different in the matched or linear models, on either a permit or per well basis.

Matching additional wells with WYPDES permits would help strengthen these results.

Difficulties encountered in pairing WYPDES permits to individual wells suggest that a more transparent regulatory framework might benefit all involved parties. In order to produce water from a CBM well, firms must receive permits from no less than three separate state agencies: the WOGCC for a well permit, the state engineer for an appropriative water right, and the WYDEQ for a discharge permit. Not only does this triple the fixed costs developers incur, but it leaves barriers to effective communication across regulatory authorities. A single agency with authority for all aspects of CBM permitting would reduce costs and potentially give better results by exercising more comprehensive authority. The risk in consolidating authority is that regulatory capture might be more easily achieved.

Over time firms have increased the number of wells covered by each permit. This can be alternatively explained as an attempt to spread the fixed costs of permit application over more wells or as a violation risk minimization strategy. Since split estate wells have been developed later in time, we might expect water disposal techniques to be more refined, and thus less likely to result in a violation. However, as time has progressed, developers have moved into different coals that have less potable water, which tends to increase the likelihood of a violation. As permits have been revised to cover more wells, there is more overlap of split and unified wells on the same permit. This suggests that the costs of obtaining and maintaining a WYPDES permit may outweigh any tenure-based effects. Understanding how the choices firms make to comply with environmental regulations balance risk and cost would not only make the WYPDES data much more useful, but would provide an interesting more general result.

Two final related topics are interesting. The value of water is not fully-captured by markets, especially in western states where the prior appropriative doctrine values water quantity but not quality. Valuing water as a non-market good is not undertaken here, but is a plausible extension to this work.

The long-term effects of CBM development and water discharge are not yet clear since very few wells have been depleted to the point that they are abandoned and finally reclaimed. One advantage to using water permit violations in this study is that the dewatering and disposal process is during the initial phase of production. These are the effects that are being felt now. The thoroughness and efficacy of reclamation will affect the final balance of environmental costs, but it is not yet clear how. There may also be longer-term effects of discharge as higher flows affect riparian ecosystems.

Tables

Table 1: CBM Wells and WYPDES Violations

Tenure	*Reported*			*Mapped*		
	Violation	Total	%	Violation	Total	%
Federal Unified	506	10374	4.88	103	3486	2.95
Federal Split	150	4049	3.70	724	15391	4.70
Total Federal Minerals	656	14423	4.55	827	18877	4.38
Private Unified	694	20160	3.44	560	17593	3.18
State Unified	103	4149	2.48	.	.	.
Other	69	1732	3.98	136	3991	3.41
Total Non-Federal Minerals	866	26041	3.33	696	21594	3.22
Total	1523	40464	3.76	1523	40461	3.76

Table 2: WYPDES Permit Violations
n=953

	p25	Median	p75	Max	Mean	None
Number of Violations	9	27	80	3456	88	0
Minor Violations	6	18	56	2496	66	79
Letter of Violation	0	4	20	768	20	372
Notice of Violation	0	0	0	139	1.3	873
Serious Violations	0	0	0	139	0.7	918

Table 3: WYPDES Permit Violations for CBM Wells Over Time

	Total	Pre-2000	2000	2001	2002	2003	2004	2005	2006
Initial Monitoring Report	12254	0	23	3500	3532	3042	1124	684	349
Administrative Order	576	48	36	0	22	5	0	329	145
Comment	47023	30	69	396	1432	5663	9664	16198	13568
Compliance Inspection	2859	6	548	583	32	663	488	246	0
Letter of Violation--Effluent	9101	0	802	822	2223	3481	1116	435	222
Letter of Violation--Other	10041	55	469	1636	2842	1197	999	1123	1693
Notice of Violation	1261	10	36	0	150	5	15	703	342
Penalty Recommended	683	0	0	0	94	0	15	377	197
Under Criminal Review	22	0	0	0	22	0	0	0	0
Subtotal	83846	149	1983	6937	10642	14056	13421	20086	16516
Not Entered	56	33	0	0	0	7	16	0	0
TOTAL	83876	182	1983	6937	10642	14063	13437	20086	16516

Table 4: Tenure of Wells Matched to WYPDES Permits

Reported	Min	Median	Mean	Max	None	Total
All Wells	1	10.5	23.78	270	0	1522
Split Wells	0	0	2.34	55	42	150
Unified Wells	0	2	7.91	103	21	506
Other Tenures	0	5	13.5	121	6	866
Mapped	Min	Median	Mean	Max	None	Total
All Wells	1	10.5	23.78	270	0	1522
Split Wells	0	3	11.3	144	12	724
Unified Wells	0	0	1.59	21	45	102
Other Tenures	0	5	10.9	105	8	696

Table 5: Ordinal Severity of Violations

	Severity
Initial Monitoring Report	1
Administrative Order	1
Comment	1
Compliance Inspection	1
Letter of Violation (Any)	2
Notice of Violation	3
Penalty Recommended	4
Under Criminal Review	4

Table 6A: Observations by Propensity Score Block

Reported

Block	Score	Control	Treated	Total
1	0	2686	49	2735
2	0.025	281	12	293
3	0.05	641	21	662
4	0.1	2408	347	2755
5	0.2	799	262	1061
6	0.25	386	158	544
7	0.275	284	188	472
8	0.3	445	242	687
9	0.35	225	123	348
10	0.375	180	162	342
11	0.4	1255	1181	2436
12	0.6	231	391	622
13	0.7	103	236	339
14	0.8	45	493	538
		9969	3865	13834

Mapped

Block	Score	Control	Treated	Total
1	0	562	447	1009
2	0.2	118	17	135
3	0.25	140	59	199
4	0.3	406	269	675
5	0.4	792	751	1543
6	0.6	79	84	163
7	0.625	48	61	109
8	0.6375	22	51	73
9	0.65	110	292	402
10	0.7	167	385	552
11	0.75	183	632	815
12	0.8	223	1009	1232
13	0.85	143	660	803
14	0.875	131	889	1020
15	0.9	74	978	1052
16	0.925	55	1193	1248
17	0.95	26	1362	1388
18	0.975	16	1667	1683
		3295	10806	14101

Table 6B: Balancing Tests

Reported

Block Number	Elevation	Township	Range
2	229.674*	-3.202**	
	(90.702)	(1.087)	
3			-2.338**
			(0.473)
5	59.533*		
	(23.463)		
7	-83.823**	0.707*	
	(28.280)	(0.361)	
10	-89.831*	1.255**	
	(40.135)	(0.479)	
11	-72.843**	0.582**	0.219**
	(19.504)	(0.221)	(0.084)
14	-266.735**	3.195**	
	(87.204)	(1.142)	

Mapped

Block Number	Elevation	Township	Range
4	38.785**	-0.655**	
	(13.564)	(0.186)	
5	86.617**	-1.068**	
	(13.126)	(0.178)	
9	107.733*		-1.139**
	(43.717)		(0.306)
10	87.803*	-1.145*	
	(35.797)	(0.523)	
11			-0.409*
			(0.199)
13		0.902*	
		(0.445)	
14	-92.871**	1.424**	0.621**
	(34.487)	(0.340)	(0.196)
15	-111.676*	1.639**	0.922**
	(44.900)	(0.514)	(0.256)
16	-275.779**	3.219**	1.440**
	(50.929)	(0.579)	(0.275)
18			-20.910**
			(3.501)

Table 7: Well-Level Matching Results: Kernel Bandwidth 0.035

Reported	Unmatched Difference	Matched Difference	Control (Unified)	Treated (Split)	Total
Violations/Permit	3.496	10.256*	9354	3829	13183
	(2.560)	(4.000)			
Violations/ Well	1.045*	2.112*	9354	3829	13183
	(0.480)	(0.750)			
Aggregate Severity of Violations/Permit	181.912**	97.904	417	137	554
	(49.181)	(112.539)			
Average Severity of Violations/Well	43.660**	22.148	417	137	554
	(9.338)	(21.154)			

Mapped	Unmatched Difference	Matched Difference	Control (Unified)	Treated (Split)	Total
Violations/Permit	9.742**	16.101**	2802	10370	13712
	(2.857)	(5.037)			
Violations/ Well	3.219**	3.408**	2802	10370	13172
	(0.532)	(0.410)			
Aggregate Severity of Violations/Permit	91.936	-77.379	98	450	548
	(54.769)	(161.676)			
Average Severity of Violations/Well	56.991**	-0.865	98	450	548
	(10.165)	(12.287)			

Table 8: Well-Level Matching Results: Kernel Bandwidth 0.1

Reported	Unmatched Difference	Matched Difference	Control (Unified)	Treated (Split)	Total
Violations/Permit	3.496	9.649*	9354	3829	13183
	(2.560)	(3.779)			
Violations/ Well	1.045*	2.016**	9354	3829	13183
	(0.480)	(0.711)			
Aggregate Severity of Violations/Permit	181.912**	93.864	417	137	554
	(49.181)	(108.855)			
Average Severity of Violations/Well	43.660**	19.984	417	137	554
	(9.338)	(20.450)			

Mapped	Unmatched Difference	Matched Difference	Control (Unified)	Treated (Split)	Total
Violations/Permit	9.742**	15.103**	2802	10370	13712
	(2.857)	(3.757)			
Violations/ Well	3.219**	3.221**	2802	10370	13172
	(0.532)	(0.352)			
Aggregate Severity of Violations/Permit	91.936	225.113	98	450	548
	(54.769)	(403.923)			
Average Severity of Violations/Well	56.991**	47.446	98	450	548
	(10.165)	(25.492)			

Table 9: Well-Level Matching Results: Kernel Bandwidth 0.01

Reported	Unmatched Difference	Matched Difference	Control (Unified)	Treated (Split)	Total
Violations/Permit	3.496	10.178*	9354	3829	13183
	(2.560)	(4.191)			
Violations/ Well	1.045*	2.077**	9354	3829	13183
	(0.480)	(0.784)			
Aggregate Severity of Violations/Permit	181.912**	70.198	417	137	554
	(49.181)	(118.128)			
Average Severity of Violations/Well	43.660**	17.246	417	137	554
	(9.338)	(22.189)			

Mapped	Unmatched Difference	Matched Difference	Control (Unified)	Treated (Split)	Total
Violations/Permit	9.742**	16.356**	2802	10370	13712
	(2.857)	(5.590)			
Violations/ Well	3.219**	3.450**	2802	10370	13172
	(0.532)	(0.438)			
Aggregate Severity of Violations/Permit	91.936	-2.165	98	450	548
	(54.769)	(125.886)			
Average Severity of Violations/Well	56.991**	9.752	98	450	548
	(10.165)	(11.789)			

Table 10: Linear Regression Results

	Reported	*Mapped*
Incidence		
Violations/Permit	11.352**	1.8440
	(2.6854)	(2.4755)
Violations/ Well	2.3668**	0.6328
	(0.5158)	(0.4553)
Severity		
Aggregate Severity of Violations/Permit	-0.2414	0.6877
	(0.4473)	(0.8877)
Average Severity of Violations/Well	-0.6624	3.1260
	(1.2674)	(2.5315)

Table 11: Linear Regression with Propensity Score

	Reported	*Mapped*
Incidence		
Violations/Permit	10.841**	1.8482
	(2.8926)	(3.2089)
Violations/ Well	2.2361**	0.6123
	(0.5591)	(0.6156)
Severity		
Aggregate Severity of Violations/Permit	-0.03222	0.9058
	(0.4860)	(0.5366)
Average Severity of Violations/Well	1.0875	0.9268
	(1.4199)	(1.7784)

Appendix: Technology of Coalbed Methane

Several summaries of the basic CBM production process exist (Bryner (2003), Bryner (2002), Darin (2002), Darin and Beatie (2001), Wheaton and Donato (2004), and references therein). A brief sketch of the major parts of the development process follows. Coalbed methane (CBM) has been an attractive play for developers because of its simplicity and affordability as compared to other natural gas extraction technologies. It is part of a broader move to "unconventional" deposits and extraction technologies. Conventional deposits are associated and dry gas reservoirs. Unconventional deposits include tights sands or shales and CBM. Natural gas is a volatile byproduct of the creation of coal. Conventional deposits are created where it has migrated out of the coal that created it—its "source rock." Sometimes, as in Appalachia, the gas is trapped in other geologic structures before it gets to the surface. The new formation where the gas is found is called a "reservoir rock." Geologists have long known that methane and coal go hand in hand; tragic experiences with gas explosions in coal mines have served to reinforce that lesson (Flores (1998)). Test projects during the 1970s led to anticipation of commercial CBM extraction, triggering a debate over legal ownership of gas in the legal literature.[68] Structural barriers in the market for natural gas delayed the development of CBM along with other natural gas deposits.[69] However, in time barriers to interstate trade were removed and demand grew, creating a larger market for natural

[68] The legal dispute over ownership of gas trapped in coal was finally settled by the U.S. Supreme Court in 1999 in *Amoco v. Southern Ute*. Flores (1998) outlines experimentation with vertical wells that could tap methane trapped in coals in Appalachian, Black Warrior and San Juan coals. The first producing test wells were in the Black Warrior coals in Alabama, where the first commercial projects were also located.

[69] Dahl and Matson (1998) and Finnoff et al. (2004) discuss the removal of regulatory barriers.

gas. Since 1981 CBM has been produced in commercial quantities. The earliest commercial projects were in the Black Warrior coals in Alabama. The first CBM well in Wyoming was drilled in 1987, although some earlier wells were later retrofitted by perforating them into coal horizons.[70] Tax incentives for CBM were created in 1980 (Bryner (2003)), then increased in the mid-1980s to encourage CBM exploration (Flores (1998)); these were later enhanced during the 1990s and renewed again in 2001 and 2002.

All mineral development is subject to uncertainty about the location, extent, and quality of mineral deposits. Before well construction begins, firms expend considerable effort in assessing the resources by seismic surveys and computer models of reservoir dynamics. After gathering information, a developer will make decisions about where, when, and how to drill wells so as to maximize the value of the resources. Using directional drilling techniques gas can be extracted without ever setting foot directly above the deposit. However, the marginal costs of these techniques are generally higher than traditional vertical drilling. As a result, directional drilling for CBM is not observed in Wyoming.

Another important factor is that CBM reserves are much shallower than undepleted conventional reserves. Whereas some natural gas wells in the Pinedale Anticline of western Wyoming are 15,000 feet deep, the mean depth of CBM wells in northeastern Wyoming is 1073 feet. Shallower wells are much cheaper to drill.

[70] The WOGCC data show the earliest production from CBM wells in 1978. Only 13 different wells produced until 1987, and these early wells are regarded as test wells. Some other older wells were perforated into coal horizons, so the data show some spurious earlier dates. However, since none of these wells were drilled on either federal unified or federal split tenures, they are not included in the empirical results. For the purposes of the analysis of split estate, 1987 is the first year of commercial CBM development in Wyoming. Widespread development did not begin until the mid-1990s.

First a firm obtains a prospect parcel, either by lease or purchase. In the case that the parcel is split estate, the developer must obtain legal access to the surface, either by private agreement (surface-use agreement) or by bonding-on. After obtaining rights to a prospect and identifying a well site the developer must obtain a permit to drill (APD) from the state. This regulatory process is usually mundane, with an avowed goal of the WOGCC to expedite processing of permit applications. It is significant that after a permit has been issued the developer has only 180 days to "spud," or start drilling the well. If drilling does not start during this window, the permit will expire, and the developer will have to reapply. This time constraint creates an artificial urgency for the developer. Firms always try to keep their drilling crews busy since they are a limiting factor in CBM development.[71]

Other infrastructure may have to be put into place before wells can be drilled. Since many areas with CBM resources are almost completely undeveloped, roads often have to be built along with power lines and pipelines for collecting produced gas. Once the necessary preliminaries (land and seismic surveys, road-building, earthmoving, etc.) have been completed and access put into place, the actual borehole can be drilled. Much of the coalbed gas being developed today is at relatively shallow depths, so smaller rigs are used. These smaller rigs are similar to "workover rigs" seen in deeper petroleum and tight sands fields—they are similar to familiar water well rigs. The shallow depth means that the well can be drilled in a short period of time, sometimes only one week. During the drilling process there is steady traffic of drilling and service crews. The short-run impacts of development are

[71] Kellogg (2007) identified the substantial efficiency gains achieved by continuous developer-drilling crew relationships. Conversations with industry representatives confirm the importance of developer-driller relationships.

increased traffic and widespread disturbance of the surface. A typical oil or gas well pad is about 1 acre, with as many as 6 acres leveled during construction. In contrast, CBM wells are usually about 0.1 acre, with 0.2-1 acre disturbed during construction. (Kuipers et al. 2005, 6)

Once the desired depth has been reached a steel well casing is cemented into place in the borehole. The casing is perforated at the depth of the target formation. On the surface, the wellhead must be connected to collection pipelines for gas and water. This surface structure is commonly referred to as the “Christmas tree,” and is the main medium-term visual impact of development. Construction of a well is finished at the time of “completion” when a well provides an avenue for gas from a paying formation to market. Figure A1 gives a schematic of a CBM well.

After the well has been completed, water is pumped out of the coalbed aquifer to reduce the hydraulic pressure that holds the methane molecules to the coal surface. This is typically done by means of an electric pump but a variety of methods are employed. Occasionally generators are used in the field, but more often each wellhead in the field is hard-wired into the grid.[72] While almost all oil and gas development entails some water production, coalbed gas entails much larger and more consistent flows because aquifers are being dewatered.[73] After an initial startup

[72] One reason for the preference for hard-wired power is the salience of Clean Air Act regulations in Class I areas. See Throne (2004).
[73] Bryner (2003) includes a discussion of the differences in water production between CBM and traditional oil and gas. In CBM, water production peaks before gas; in traditional oil and gas, water production increases as product extraction wanes.

period, the average CBM well produces a decreasing amount of water over its life. Often this water is naturally of marginal quality so its disposal is a paramount issue.[74]

The volume and quality of produced water varies by coal. The largest volumes are found in the Powder River Basin, where 400 barrels per day per well is considered average (USGS (2000)). According to Boysen et al. (2002), in 2000 just the Wyoming portion of the Powder River basin accounted for 375 million barrels of produced water. Some formations have much less water, notably the San Juan Basin in New Mexico, where 25 barrels per day per well is average (USGS (2000)). The quality of water is highest in the Powder River Basin, which allows surface discharge for the large volumes of water produced there. High-quality water gives firms more options for disposal.

Three major strategies are used to dispose of produced water. First, and most cheaply, water can be directly discharged on the surface if it is sufficiently pure. Such discharges are now regulated by the National Point Discharge Elimination System (NPDES), a chapter of the Clean Water Act, which is administered by states. Discharges can be directly into surface water if the produced water is sufficiently pure, but are more commonly off-channel. This means that the water is dumped out on the surface, where it can evaporate, infiltrate, or run off down slope. Boysen et al. (2002) surveyed operators in several basins and found that surface discharge was by far the cheapest water disposal method—generally far less than $2/barrel.

A second option is to simply let the water evaporate from earthen pits or by spraying water into the air.[75] Airborne evaporators are the least-commonly used of

[74] Rice et al. (2000) and USGS (2000) provide technical analyses of produced water quality in the Powder River Basin specifically and the Rocky Mountain Region generally. A parallel issue is the contamination of potable water by hydraulic fracturing techniques. See, e.g., Sumi (2005).

the major options discussed here. Sometimes evaporation pits are not lined, raising concerns that contaminated water might infiltrate into shallow aquifers used for domestic water.

A third disposal option is to reinject or reuse the water in some way. This usually entails transporting the water to another location. Large volumes are more efficiently transported by pipeline, but in the San Juan and Raton Basins in New Mexico, where volumes and water quality are low, the saline produced water has been used for enhanced secondary recovery in nearby petroleum wells. The purer water in the Powder River Basin has been used for stock water or even as irrigation water in controlled experiments. The AMPP pilot project along the Tongue River in Montana has experimented with various treatments to allow use of saline water on sodic soils. In other areas developers have been able to entice landowners with irrigation pivots using produced water of sufficient purity.

Another option is to reinject the water into another geologic formation with sufficient volume. Unfortunately, where the volume of produced water is highest, the availability of suitable reinjection formations is most limited. At least one company has constructed a multi-million dollar pipeline to transport produced water to another part of the state where there are available formations that can be used. Later development into lower coal horizons may be able to reinject back into the shallower, previously-drained coals above them.

Once enough water has been pumped out of the ground and the pressure decreases, gas molecules will desorb from the coal surface. Wheaton and Donato

---

[75] An interesting side effect of evaporation pits is the increase in mosquito habitat, potentially increasing transmission of West Nile virus. The effect of this on bird populations, notably sage grouse, has been a topic of recent research. See Doherty et al. (2008).

(2004) point out that dewatering is more efficient if wells are completed in a grid pattern to reduce pressures over a large area, effectively dewatering aquifers. This feature of the production technology has raised concerns about groundwater mining and depletion. Putting the water back prevents the gas from desorbing and thus prevents production. For this reason it is not possible to reinject production water back into the same formation that is producing gas. Once the aquifer has been sufficiently depleted, the well will actually begin to produce gas. Provided that the well has been tied into a pipeline, the developer begins to get a marketable product.

Pipelines require compressor plants to compress the gas sufficiently to transport it via pipelines to market hubs. Because CBM gas is extracted at low pressure it requires two stages of compression before being delivered via pipeline. This requires more compression and distribution infrastructure, which implies further surface disruption and fragmentation of surface habitat. This low wellhead pressure is a consequence of tapping into diffuse energy sources.[76] Compressor stations require additional surface area and are a common source of complaint due to their round-the-clock noise in operation.

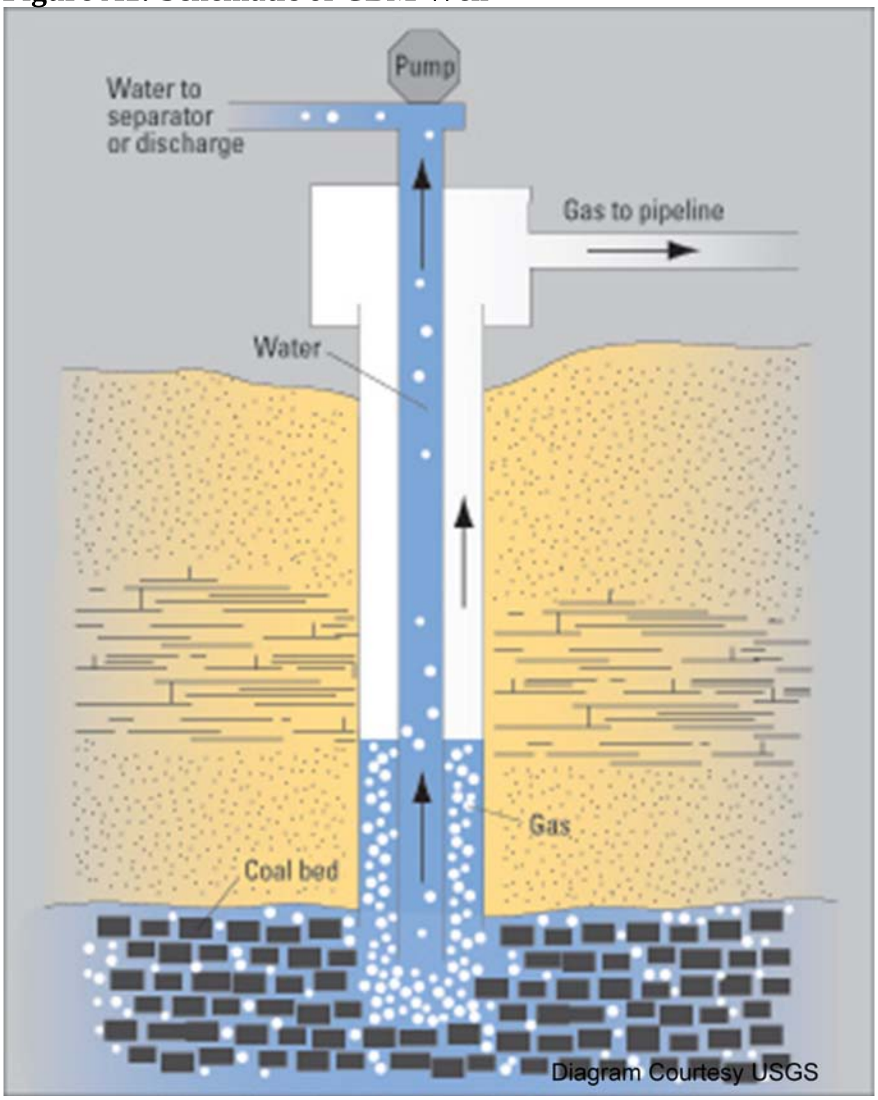
Soon after well construction is completed, the site should be reclaimed. Even after the reclamation has been done, periodically gas company personnel may need to access the well. Although telemetry is increasingly used for well checking, some long-term access is required. Two-track roads and four-wheeler tracks are common in accessible areas, but more mountainous terrain requires that improved roads be maintained to each well in the event maintenance or a workover is needed.

[76] Compression costs might be thought of in the same class as processing costs for oil shale or tar sands. Unlike processing those resources, compression requires a network of compression plants dispersed across the landscape.

Most CBM wells are expected to play out within 12-15 years. At that time the wellbore will be plugged, salvageable equipment will be removed, and the surface will be reclaimed to near its original state. The long-run impact of CBM development is hard for the untrained eye to notice.

Appendix Figures

Figure A1: Schematic of CBM Well



Conclusions

Split estate is an intriguing and prevalent institutional arrangement, particularly in the context of expanded energy development. Although it has important real world effects and has been the focus of a policy debate in states with expanding energy production, it has escaped serious study by economists until now. These essays outline and calibrate the average effects of split estate on a number of development outcomes. Previous work by Chouinard and Steinhoffer (2008) emphasizes the risk that severed surface owners pose to developers. While this work does not attempt to characterize the distribution of effects, it does quantify the expected value of surface owner risk.

Three lines of inquiry are made in the course of these essays. The first exposes how ex ante expectations in the form of prices paid for federal mineral leases are lower for split estate leases. The second examines how the optimal production path differs for CBM wells on split and unified tenures; production is later from wells that are reported as split estate. In the third essay, differences in performance of direct discharge permits for produced water suggest that split estate is associated with more numerous, but not more severe, violations of the pertinent regulations.

Developers anticipate additional costs on split estate and discount bonus payments for leases by 11-14%. The federal government generates revenue from lease sales, half of which is shared with the state in which the leases are located. In the case of split estate, the federal government does not own the surface rights and therefore cannot contract over them. However, by analyzing the effect of multiple tenures on bonus payments, we can conclude that contiguous parcels with more than one type of tenure sell at a premium. This suggests that bundling contiguous split and unified parcels may increase bonus revenues. However, this recommendation should be taken cautiously, since the effects on non-contiguous leases are not fully explored.

Comparing individual CBM wells on split and unified estate reveals that the outcomes of development differ with tenure. Entry is 3.5-11 months later on wells that are reported as split estate, but there is no significant difference in either the cumulative amount of gas extracted or on the peak monthly production level. Later entry is not associated with a delay between the initial application and first production. That time might differ if contracting with the surface owner takes time as well as money to reach a SUA. It could be that firms agree on terms of entry prior to filing a well application. In either event, the upshot is that the split estate wells are developed later. But the amount of gas that is ultimately produced, presumably representing an optimal production path, does not significantly differ.

Since the history of oil and gas production has been defined by the race to produce from common-pool deposits, this conclusion is somewhat surprising. Racing to produce from tight geologic formations such as coalbeds is apt to result in waste instead of gain by the fastest producers. Because the optimal production paths are not significantly different, we can also infer that the costs of split estate are incurred once, as fixed costs rather than variable costs that change optimal production path. As development continues, the implication of these results is that split estate represents a large societal cost that must be incurred. Whether these fixed costs are better thought of per acre or per well remains a question for future work.

One interesting anomaly is the discrepancy between reported and mapped tenures. Although there appears to be a background rate of measurement error in the recording of well sites on the order of 2-4%, an overwhelming percentage (62%) of wells that are mapped on split were reported on unified. A strong time trend in this misreporting phenomenon is evidence that developers' calculus regarding split estate has changed. Misreported wells are disproportionately high-producing. The traditional concern about common-property deposits and the attendant race to produce is so engrained in developers' minds that that they look for any advantage that might expedite the development process. The production results suggest that optimal production paths do not differ, likely because of the tight geological nature of CBM deposits. Because deposits don't migrate, the incentive to race to produce is weakened. Alternatively, the higher profile of split estate due to political debate may have been enough to scare developers straight. Future research can parse which of these explanations dominates.

The third essay explores how compliance with regulations pertaining to direct discharge of produced water differs with tenure. Despite identical applicable regulations, there is evidence that both permits covering split estate wells and split estate wells themselves have more numerous violations, although not necessarily a higher incidence. Reported split estate wells on water discharge permits in violation have about 2 more violations than comparable unified wells; permits covering reported split estate wells have about 10 more violations than those covering unified wells. The severity of those violations is not different from what is seen on unified permits or wells.

One observation regarding the production and disposal of water from CBM wells is that the regulatory environment is highly fragmented. Operators must obtain a well permit from the WOGCC, an appropriation of groundwater from the state engineer, and then a discharge permit from WYDEQ. Since each agency has a narrowly-defined mission, the entire picture of the production and disposal of enormous amounts of groundwater is not within the scope of any single overseer. Many residents have complained about the lack of a unified plan for development, consolidation of a regulatory authority seems intuitive.

Bibliography

Adelman, M. A. 1992. Finding and Developing Costs in the Unites States, 1945-1986. *Advances in the Economics of Energy and Resources*. 7: 11-58.

Alspach, Christopher M. 2002. Surface Use by the Mineral Owner: How Much Accommodation is Required under Current Oil and Gas Law? *Oklahoma Law Review*. 55:89-119.

Amoco Production Company v. Southern Ute Tribe. (98-830) 526 U.S. 865 (1999)

Anderson, Owen L. and Ernest E. Smith. 1999. The Use of Law to Promote Domestic Exploration and Production. *Petroleum Accounting and Financial Management Journal*. 50(18): 1-11.

Anderson, Terry L. and P. J. Hill. 2004. The Not so Wild, Wild West: Property Rights on the Frontier. Stanford, CA: Stanford University Press.

Athey, Susan and Jonathan Levin. 2001. Information and Competition in U.S. Forest Service Timber Auctions. *Journal of Political Economy*. 109(2): 375-417.

Baldwin, Laura H., Robert C. Marshall, and Jean-Francois Richard. 1997. Bidder Collusion at Forest Service Timber Sales. *Journal of Political Economy.* 105(4): 657-699.

Barzel, Yoram. 1997. Economic Analysis of Property Rights. 2nd edition. Cambridge University Press: New York, NY.

Bento, Antonio, Charles Towe, and Jacqueline Geoghegan. 2008. The Effects of Moratoria on Residential Development. *American Journal of Agricultural Economics*. 89(5): 1211-1218.

Black, Geoffrey. 2002. A Transaction Cost Model of Contract Choice: The Case of Petroleum Exploration. *International Advances in Economic Research*. 8(3): 235-247.

Black, Dan A. and Jeffrey A. Smith. 2004. How Robust is the Evidence on the Effects of College Quality? Evidence from Matching. *Journal of Econometrics*. 121: 99-124.

Bohi, Douglas R. 1998. Changing Productivity in U.S. Petroleum Exploration and Development. Resources for the Future Discussion Paper 98-38. Resources for the Future: Washington, D.C.

Bohn, Henning and Robert T. Deacon. 2000. Ownership Risk, Investment, and the Use of Natural Resources. *American Economic Review*. 90(3): 526-549.

Boskin, Michael J., Marc S. Robinson, Terrance O'Reilly, and Praveen Kumar. 1985. New Estimates of the Value of Federal Mineral Rights and Land. *American Economic Review*. 75(5): 923-936.

Boysen, Deidre B., John E. Boysen, and Jessica A. Boysen. 2002. Strategic Produced Water Management and Disposal Economics in the Rocky Mountain Region. BC Technologies, Ltd.: Laramie, WY.

Bryner, Gary D. 2003. Coalbed Methane Development: Costs and Benefits of an Emerging Resource. *Natural Resources Journal*. 42(3): 519-560.

Cameron, A. Colin, and Pravin K. Trivedi. 2005. Microeconometrics: Methods and Applications. New York, NY: Cambridge University Press.

Capen, E.C., R.V. Clapp, and W.M. Campbell. 1971. Competitive Bidding in High-Risk Situations. *Journal of Petroleum Technology*. : 641-653.

Chermak, Janie M. and Robert H. Patrick. 1995. A Well-Based Cost Function and the Economics of Exhaustible Resources: The Case of Natural Gas. *Journal of Environmental Economics and Management.* 28: 174-189.

Chouinard, Hayley and Christina Steinhoffer. 2008. Split Estate Negotiations: The Case of Coal-Bed Methane. *Review of Law & Economics*. 4(1): 233-258.

Copp, E. Anthony. 1974. Technical Change and Petroleum Drilling Costs. *Land Economics*. 50(2): 120-126.

Copp, E. Anthony. 1976. Technical Change and Petroleum Drilling Costs: Reply. *Land Economics*. 52(1): 109-116.

Cox, Randall T. 2001. Easements, Access & Eminent Domain A Review of Wyoming Law. Second Edition. Gillette, Wyo.: Prairie Dog Press.

Dahl, Carol A., and Thomas K. Matson. 1998. Evolution of the U.S. Natural Gas Industry in Response to Changes in Transaction Costs. *Land Economics*. 74(3): 390-408.

Darin, Thomas F. 2002. Waste or Wasted?—Rethinking the Regulation of Coalbed Methane Byproduct Water in the Rocky Mountains: A Comparative Analysis of Approaches to Coalbed Methane Produced Water Quantity Issues in Utah, New Mexico, Colorado, Montana, and Wyoming. *Journal of Environmental Law and Litigation*. 17: (281-341).

Darin, Thomas F. and Amy W. Beatie. 2001. Debunking the Natural Gas "Clean Energy" Myth: Coalbed Methane in Wyoming's Powder River Basin. *Environmental Law Reporter*. 31:5 10566-10602.

Davis, Rick D., Jr. 2004. Conflicts between Surface Owners and Mineral Lessees. *Public Land & Resources Law Digest*. 41: 93-135.

Deacon, Robert T. 1993. Taxation, Depletion, and Welfare: A Simulation Study of the U.S. Petroleum Resource. *Journal of Environmental Economics and Management*. 24(2): 159-187.

Dehejia, Rajeev H., and Sadek Wahba. 2002. Propensity Score-Matching Methods for Nonexperimental Causal Studies. *Review of Economics and Statistics*. 84(1): 151-161.

Dehejia, Rajeev H., and Sadek Wahba. 1999. Causal Effects in Nonexperimental Studies: Reevaluating the Evaluation of Training Programs. *Journal of the American Statistical Association*. 94:448 1053-1062.

Dennen, R. Taylor. 1976. Cattlemen's Associations and Property Rights in Land in the American West. *Explorations in Economic History*. 13: 423-436.

Doherty, Kevin E., David E. Naugle, Brett L. Walker, and Jon M. Graham. 2008. Greater Sage-Grouse Winter Habitat Selection and Energy Development. *Journal of Wildlife Management*. 72(1): 187-195.

Farnsworth, Richard L. and Richard B. Norgaard. 1976. Technical Change and Petroleum Drilling Costs: Comment. *Land Economics*. 52(1): 103-115.

Finnoff, David, Curtis Cramer, and Sherrill Shaffer. 2004. The Financial and Operational Impacts of FERC Order 636 on the Interstate Natural Gas Pipeline Industry. *Journal of Regulatory Economics*. 25(3): 243-270.

Flores, Romeo. 1998. Coalbed Methane: From Hazard to Resource. *International Journal of Coal Geology*. 35: 3-26.

Gates, Paul W. 1968. <u>History of Public Land Law Development.</u> Washington, DC: U.S. GPO.

Gaudet, Gerard, Michel Moreaux, and Cees Withagen. 2006. The Alberta dilemma: optimal sharing of a water resource by an agricultural and an oil sector. *Journal of Environmental Economics and Management*. 52: 548-566.

Gerking, Shelby and William Morgan. 2007. Effects of Environmental and Land Use Regulation in the Oil and Gas Industry Using the Wyoming Checkerboard as an Experimental Design: Retraction. *American Economic Review*. 97(3): 1032.

Government Accountability Office. 2008. Oil and Gas Leasing: Interior Could Do More to Encourage Diligent Development. GAO-09-74. Government Accountability Office: Washington, DC.

Gruy, H. J. 2000. History of the Ownerships of Mineral Rights. Paper for SPE Technical Conference 1-4 October, 2000. 441-443.

Haile, Philip A. 2001. Auctions with Resale Markets: An Application to U.S. Forest Service Timber Sales. *American Economic Review*. 91(3): 399-427.

Hansen, Zeynep K., and Gary D. Libecap. 2004. The Allocation of Property Rights to Land: US Land Policy and Farm Failure in the Northern Great Plains. *Exploration in Economic History*. 41: 102-129.

Heckman, James J., Hidehiko Ichimura, and Petra E. Todd. 1998. Matching as an Econometric Evaluation Estimator. *Review of Economic Studies.* 65: 261-294.

Heckman, James J., Hidehiko Ichimura, and Petra E. Todd. 1997. Matching as an Econometric Estimator: Evidence from Evaluating a Job Training Programme. *Review of Economic Studies.* 64: 605-654.

Hendricks, Kenneth, and Robert H. Porter. 1988. An Empirical Study of an Auction with Asymmetric Information. *American Economic Review*. 78(5): 865-883.

Hill, Drake D. and P. Jaye Rippley. 2004. The Split Estate: Communication and Education versus Legislation. *Wyoming Law Review*. 4(2): 585-605.

Holland, Stephen P. 2003. Extraction Capacity and the Optimal Order of Extraction. *Journal of Environmental Economics and Management*. 45: 569-588.

Huffman, James L. 1982. The Allocative Impacts of Mineral Severance: Implications for the Regulation of Surface Mining. *Natural Resources Journal*. 22: 201-237.

Imbens, Guido W. 2004. Nonparametric estimation of average treatment effects under exogeneity: a review. *Review of Economics and Statistics*. 86(1): 4-29.

Kellogg, Ryan. 2007. Learning by Drilling: Inter-Firm Learning and Relationship Persistence in the Texas Oil Patch. Working Paper, Department of Agriculture and Resource Economics, University of California-Berkeley.

Kuipers, Jim, Victoria Lynne, and Kimberley MacHardy. 2005. Filling the Gaps: How to Improve Oil and Gas Reclamation and Reduce Taxpayer Liability. Western Organization of Resource Councils: Billings, MT.

Kunce, Mitch, Shelby Gerking, and William Morgan. 2002. Effects of Environmental and Land Use Regulation in the Oil and Gas Industry Using the Wyoming Checkerboard as an Experimental Design. *American Economic Review*. 92(5): 1588-1593.

Kunce, Mitch, and William E. Morgan. 2005. Taxation of Oil and Gas in the United States, 1970-1997. *Natural Resources Journal*. 45:77-101.

Leung, Siu Fai, and Shihti Yu. 1996. On the Choice between Sample Selection and Two-Part Models. *Journal of Econometrics*. 72:197-229.

Libecap, Gary D. and Zeynep K. Hansen. 2002. "Rain Follows the Plow" and Dryfarming Doctrine: The Climate Information Problem and Homestead Failure in the Upper Great Plains, 1890-1925. *Journal of Economic History*. 62(1): 86-120.

Libecap, Gary D. and James L. Smith. 2002. The Economic Evolution of Petroleum Property Rights in the United States. *Journal of Legal Studies*. 31: S589-S608.

Libecap, Gary D. and Steven N. Wiggins. 1985. The Influence of Private Contractual Failure on Regulation: The Case of Oil Field Unitization. *Journal of Political Economy*. 93(4): 690-714.

List, John A., Daniel L. Millimet, Per G. Fredriksson, and W. Warren McHone. 2003. Effects of Environmental Regulations on Manufacturing Plant Births: Evidence from a Propensity Score Matching Estimator. *Review of Economics and Statistics*. 85(4): 944-952.

Lynch, Lori, Wayne Gray, and Jacqueline Geoghegan. 2007. Are Farmland preservation Program Easement restrictions Capitalized into Farmland Prices? What Can a Propensity Score Matching Estimator Tell Us? *Review of Agricultural Economics*. 29(3): 502-509.

McDonald, Stephen L. 1979. The Leasing of Federal Lands for Fossil Fuels Production. Baltimore, MD: Johns Hopkins University Press for Resources for the Future.

McFerrin, Randy, and Douglas Wills. 2007, High Noon on the Western Range: A Property Rights Analysis of the Johnson County War. *Journal of Economic History*. 67(1): 69-92.

McPhee, John. 1986. Rising from the Plains. New York: Noonday Press.

Mergen, Andrew C. 1998. Surface Tension: The Problem of Federal/Private Split Estate Lands. *Land and Water Law Review*. 33: 419-467.

Micheli, Matt. 2006. Showdown at the OK Corral—Wyoming's Challenge to U.S. Supremacy on Federal Split Estate Lands. *Wyoming Law Review*. 6:1 31-51.

Mokyr, Joel. 2002. The Gifts of Athena: Historical Origins of the Knowledge Economy. Princeton University Press: Princeton, N.J.

Moody, C.E., Jr., and W.J. Kruvant. 1990. OCS Leasing Policy and Lease Prices. *Land Economics*. 66(1): 30-39.

Moody, C.E., Jr., and W.J. Kruvant. 1988. Joint Bidding, Entry, and the Price of OCS Leases. *RAND Journal of Economics*. 19(2): 276-284.

Nelson, Robert H. 1995. Public Lands and Private Rights: The Failure of Scientific Management. Lanham, MD: Rowman & Littlefield.

Nelson, Robert H. 1983. The Making of Federal Coal Policy. Durham, NC: Duke University Press.

Paddock, James L., Daniel R. Siegel, and James L. Smith. 1988. Option Valuation of Claims on Real Assets: The Case of Offshore Petroleum Leases. *Quarterly Journal of Economics*. 103(3): 479-508.

Porter, Robert H. 1995. The Role of Information in U.S. Offshore Oil and Gas Lease Auctions. *Econometrica*. 63(1): 1-27.

Rice, C. A., M. S. Ellis, and J. H. Bullock, Jr. 2000. Water co-produced with coalbed methane in the Powder River Basin, Wyoming: preliminary compositional data. USGS Open-File Report 00-372. USGS: Denver, CO.

Rosenbaum, Paul R., and Donald B. Rubin. 1983. The Central Role of the Propensity Score in Observational Studies for Causal Effects. *Biometrika*. 70:1 41-55.

Silverman, B. W. 1986. Density Estimation for Statistics and Data Analysis. New York, NY: Chapman and Hall.

Smith, Jeffrey A. and Petra E. Todd. 2005. Does Matching Overcome LaLonde's Critique of Nonexperimental Estimators? *Journal of Econometrics*. 125: 305-353.

Sumi, Lisa. 2005. "Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know About Hydraulic Fracturing." Durango, CO: Oil and Gas Accountability Project.

Swenson, Robert W. 1968. Legal Aspects of Mineral Resources Exploitation. in Gates, Paul W. 1968. History of Public Land Law Development. Washington, DC: U.S. GPO.

Throne, Mary A. 2004. "Air Quality Issues in Coalbed Methane Development." *Wyoming Law Review*. 4(2): 643-666.

USGS. 2000. Water Produced with Coal-Bed Methane. USGS Fact Sheet 156-00. USGS: Denver, CO.

Wheaton, John and Teresa Donato. 2004. Coalbed-Methane Basics: Powder River Basin, Montana. Montana Bureau of Mines and Geology Information Pamphlet 5. Montana Bureau of Mines and Geology.

Whinston, Michael D. 2003. On the Transaction Cost Determinants of Vertical Integration. *Journal of Law, Economics, & Organization*. 19(1): 1- 23.

Wiggins, Steven N. and Gary D. Libecap. 1985. Oil Field Unitization: Contractual Failure in the Presence of Imperfect Information. *American Economic Review*. 75(3): 368-385.

Williams, Steven R. 1990. The Transition from Bargaining to a Competitive Market. *American Economic Review*. 80(2): 227-231.

Yergin, Daniel. 1991. The Prize: The Epic Quest for Oil, Money & Power. New York: Free Press.