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Capturing Rents from Natural Resource Abundance: Private Royalties from U.S. Onshore Oil & Gas Production[*]

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Abstract

We study how much private mineral owners capture geologically-driven advantages in well productivity through a higher royalty rate. Using proprietary data from nearly 1.8 million leases, we estimate that the six major shale plays generated $39 billion in private royalties in 2014. There is limited pass-through of resource abundance into royalty rates. A doubling of the ultimate recovery of the average well in a county increases the average royalty rate by 1 to 2 percentage points (a 6 to 11 percent increase). Thus, mineral owners benefit from resource abundance primarily through a quantity effect, not through negotiating better lease terms from extraction firms. The low pass-through likely reflects a combination of firms exercising market power in private leasing markets and uncertainty over the value of resource endowments.

JEL codes: L71, R11, Q32, Q35
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I. Introduction

During the 2000s, innovation in extracting oil and gas from shale formations caused the U.S. to become the global leader in producing oil and natural gas (EIA, 2013). Because shale formations lie primarily on private lands, drilling companies access the resource through private lease contracts that provide a share of the value of production–a royalty–to mineral owners. Using a proprietary dataset of nearly 1.8 million oil and gas leases, we make two contributions to the understanding of royalties and royalty rates in the United States. First, we quantify the economic importance of royalties to various regions by estimating royalty income flows and comparing them to what residents receive in other income transfers—government transfer income and total farm program payments. We are aware of no published studies quantifying royalty income to different regions despite its potentially large effect on local income and wealth (Gilje 2012; Pender et al. 2014).[1]

The second contribution is an estimate of the extent that resource abundance passes through to mineral owners via higher royalty rates. If mineral acreage is fixed, competition and free entry should ensure that mineral owners capture Ricardian rents–the additional revenues generated by a given parcel because it has a greater endowment of oil and gas. Mineral owners in resource-abundant areas would therefore capture a larger share of the value of production than owners in less abundant areas. Weyl and Fabinger (2013) note that most work on pass-through assumes perfect competition despite scant empirical evidence in many markets. This is potentially true of the private oil and gas leasing market, which is surprisingly understudied given the hundreds of billions of revenue that private leases generate.

[1] Hardy and Kelsey (2015) show that local ownership of land varies across Pennsylvania counties in the Marcellus shale and thus the potential for varying local ownership of lease and royalty payments. However, patterns in surface and mineral right ownership need not be the same in a given area.

We estimate that in 2014 the six major U.S. shale plays generated a total of $39 billion in royalties. This is more than four times the royalty income received by the Federal government in the same year (Office of Natural Resources Revenue, 2015). In the more rural plays, private royalties rival government transfer income and swamp farm program payments. We also observe that average royalty rates vary substantially across plays, from a low of 13.2 percent in the Marcellus to a high of 21.2 percent in the Permian, as does the share of ownership by county residents (12 to 55 percent).

Using spatial variation in royalty rates and resource abundance, we estimate that a doubling of the estimated ultimate recovery of the typical oil and gas well in the county increases the average royalty rate by 1 to 2 percentage points at most (a 6 to 11 percent increase). This is far less pass-through than what a model of perfect competition in leasing markets predicts. It likely reflects a combination of market power in leasing markets and uncertainty. Although some pass-through may occur through signing (bonus) payments, accounting for such payments still leads to the conclusion that oil and gas abundance has a small effect on the share of production value captured by mineral owners. Thus, mineral owners benefit from resource abundance primarily through greater production, not by negotiating better lease terms from extraction firms.

II. Leasing Markets

We provide a brief overview of oil and gas leasing markets to give a foundation for our theoretical model and for interpreting our empirical results. Acquisition of prospective acreage by extraction companies in the United States has historically occurred through two channels: auction of minerals owned by federal or state governments, and negotiation of private lease contracts with individual owners of mineral property (Ravagnani, 2008). Prior research on leasing focused on the first channel–namely the leasing of federal lands and waters (e.g. Boskin et al. 1985, Hendricks and Porter 1996). We focus on the more economically important second channel.

Unlike most countries, private individuals own most of the subsurface resources in the United States (Williamson and Daum, 1959). However, mineral rights can be sold or conveyed separately from surface rights. For this reason, the ownership of most prospective oil and gas acreage has traditionally been fragmented among numerous private owners competing with one another in negotiating with companies (McKie, 1960). Oil and gas extraction historically has involved thousands of small "independent" companies, which yielded a high degree of competition in the leasing market (Davidson, 1963).

The majority of oil and gas production in the U.S. occurs via oil and gas leases as opposed to direct mineral ownership of the extracting firm (Fitzgerald and Rucker, 2016). There are two main types of ownership in oil and gas–working interests and royalty interests. Working interest owners incur all of the costs and liabilities of development but must pay the royalty interest owner a share of the gross value of production as a royalty, with the share known as the royalty rate. Royalty and working interests share price and production risk, but the working interest carries all of the cost risk and environmental liabilities associated with production.

Leasing contracts are signed before drilling occurs and are generally structured as multi-year option contracts that provide the firm the right, but not the obligation, to explore for oil and gas. If the firm finds productive deposits and pursues extraction, the lease remains in effect so long as production continues.

Oil and gas resources are not uniformly distributed, which creates the possibility of larger Ricardian rents for richer deposits. Resource abundance, commonly measured by estimates of ultimate resource recovery, varies substantially across space, even within similar formations (Ikonnikova et al. 2015). Because expected ultimate recovery varies across space, with some counties overlying “sweet spots” in the formation, some counties are potentially more profitable than others, with a given fixed investment providing access to more resource. An owner in a higher-profit area may be able to capture a larger share of the rents than an owner in a lower-profit county.

Yet, there are reasons why mineral owners may capture little of the geological richness associated with their rights. Equipped with teams of geologists and engineers, extraction firms have more information about resource abundance than the typical mineral owner. This creates a potential information asymmetry for the mineral owner. Moreover, the lease terms are set before production occurs. Most leases are written such that the lease remains in effect as long as production occurs, which prevents the mineral owner from using newly acquired information to hold up the lessee by negotiating a higher lease.

On the other hand, mineral owners can share information with each other—informally or through formal landowners’ groups. Most importantly, once extraction firms begin bidding against each other, information on offered royalty rates is likely to spread quickly amongst local mineral owners (and potentially to absentee owners via internet forums). With competition among well-informed leasing firms, the difference between what firms and mineral owners know about the subsurface becomes less important, if not irrelevant.

The long life of most leases limits opportunities for mineral owners to renegotiate new terms in response to new information. Comparatively, farmland rental leases provide more opportunities for renegotiation because the leases can be as short as one year. Yet, even with opportunities for renegotiation, there is evidence that farmland rental markets are far from perfectly competitive. Kirwan (2009) studies how a guaranteed $1 more in farm revenue (through per acre subsidies) passes through to landowners in the form of higher rental rates. He finds that only 21 cents on the dollar passes to landowners, leaving the farmer with about three quarters of the subsidy. Hendricks et al. (2012) estimate a higher long-run pass-through (37 cents on the dollar), but still well below what is implied by perfect competition.

In our study, the extraction firm is in the same position as the farmer. We expect less pass-through to occur in oil and gas leasing markets. Agricultural landowners likely know more about the relative quality of their land than mineral owners know of the oil and gas in their ground. Moreover, farmland leases can typically be renegotiated every year (or every few years) while oil and gas leases remain effective for the life of a producing well, which can be decades. Moreover, uncertainty about the location and richness of deposits gives rise to potential rents for firms with superior information, as suggested by empirical evidence from Hendricks and Porter (1988, 1996).

Empirical academic research on private oil and gas leasing markets is quite limited, in part because of the considerable difficulty of compiling a comprehensive dataset. Timmins and Vissing (2014) address lease negotiations in a Coasean bargaining framework, with empirical results supporting the idea that mineral owners have heterogeneous reservation values due to different preferences to avoid risks associated with development. Vissing (2015) finds a negative correlation between the strength of lease terms and concentration of minority households, broadening the number of possible sources of heterogeneity in value.

III. Theoretical Model

We develop a theoretical model to guide our empirics. We treat oil and gas as a single output and define production in period *t* as q_t, implying an ultimate recovery of $Q = \sum_{t=1}^{T} q_t$, where T is the expected time horizon of production. If production is uncertain, the ultimate recovery is based on probability distributions of production common to all firms. Uncertainty surrounding Q is why the industry refers to estimated ultimate recovery, or simply EUR.

Ultimate recovery matters but so do development costs. For each unit of land indexed by i, the firm incurs a fixed cost of development c_i. Firms decide which parcels to develop by weighing fixed development costs against the estimated ultimate recovery, Q_i. This is consistent with Anderson et al. (2014), who find that once irreversible development costs have been made, production is largely unresponsive to prices and instead is determined by geophysical decline. Marginal production cost can be accommodated by considering the price a net price received.

Following Leland (1978), firm preferences for managing risk related to ultimate recovery and future prices motivates the choice of a share contract, where the mineral owner is paid a share of the gross value of production, with the share known as the royalty rate ($\rho_i \in (0,1)$). The gross revenue stream is price times the quantity produced and has a present value of $R_i = \sum_{t=1}^{T} \beta^t \widetilde{p_t} \cdot q_{it}$ where $\widetilde{p_t}$ is an expected price path and β a discount factor, both of which are common to all firms. Based on the development costs and expected value of production, firms use backward induction to solve for the royalty rate they are willing to offer the parcel's owner.

To determine how many parcels are developed, assume that every firm has a periodic hurdle rate that is the risk-adjusted market rate *r*, and that $\beta = \frac{1}{1+r}$. Firms incur the fixed expenditure c_i immediately and realize the present value of production revenues in the following periods. We assume that parcels are homogeneous (allowing us to dispense with the *i* subscript) but that mineral owners have different reservation values that must be met for them to sign a lease. Profit maximization requires that firms lease the optimal number of parcels as determined by:

$$\max_{N} \pi = N[(1-\rho)R - (1+r)c],$$

which is subject to a participation constraint by all leased mineral owners:

$$\rho R \geq g(N).$$

This constraint allows for an individual-specific reservation value expressed in present value when production begins. We assume $g(N)$ is a continuous and non-decreasing function, so the last lease will just satisfy the owner's participant constraint.

Economic profit is driven to zero in a competitive market, so a zero-profit condition applies for the marginal lease:

$$(1 - \rho)R = (1 + r)c. \quad (1)$$

By rearranging the zero-profit condition, the competitive royalty rate is defined as a function of the net expected profit from the marginal parcel.

$$\rho = 1 - \frac{(1+r)c}{R}. \quad (2)$$

By taking logarithms, equation (2) can be linearized as

$$\ln(1-\rho) = -\ln(R) + \ln(1+r) + \ln(c), \quad (3)$$

which shows that in a competitive market a one percent increase in the present value of revenues is associated with a one percent decrease in the share of the value of production going to the firm, $(1-\rho)$. A mineral owner therefore captures the benefit of having more oil or gas in his property by receiving a larger share of the value of production compared to an owner whose lease grants access to less oil or gas.

The model does not consider compensation through a one-time fixed payment often paid to mineral owners upon signing a lease and referred to as a bonus payment. Hendricks et al.

(1993) show that a mineral owner could extract all rents through a fixed payment by holding a first-price, sealed-bid auction where only uninformed firms are allowed to bid. However, the inability for mineral owners (private or public) to undertake such an auction to capture all the rents (and a preference for managing risk) causes compensation to occur through both an ex-ante bonus payment and an ex-post royalty. Our theoretical and empirical models focus on royalties, but in a later section we consider the effects of accounting for changes in bonus payments in our estimates of pass-through.

A. Monopsony

First-mover advantages and spatial economies of scale in development may result in only one company acquiring a dominant acreage position in an area.[2] As a limiting case, consider the situation when only one firm leases minerals in an area.[3] When acquiring parcels to develop, the monopsonist considers how many additional parcels can be leased if it offers a higher royalty rate. If the monopsonist cannot discriminate by offering individual royalty rates to different mineral owners, increasing the royalty rate for the marginal mineral owner means increasing it for all owners (see appendix A.1 for a discussion of the case with discrimination). It therefore offers a royalty rate different from the one in (2). The new optimal royalty rate is:

$$\rho^M = 1 - \rho'(N)N - \frac{(1+r)c}{R}, \tag{4}$$

[2] The spatial economies of scale would stem from the ability to spread some development costs across nearby parcels. One access road, for example, can be used to access multiple parcels in an area. The average cost of development will then decline with the total acreage in a given region that the firm already controls, creating an incentive to consolidate acreage. For a given area, it also limits the ability of firms to compete with the firm with enjoying a dominant acreage position.

[3] The competitiveness of leasing markets is difficult to assess empirically. Even a few competing bidders could yield a competitive outcome, particularly in a setting where leases can be resold. Conversely, accusations of bid-rigging and collusion in leasing markets are common.

where N is the number of parcels leased. This rate is lower than the competitive rate by an amount determined by $\rho'(N)N$. The participation constraint binds for the marginal mineral owner so that $\rho(N)R = g(N)$. By substitution, $\rho'(N)N = \frac{g'(N)N}{R} = \gamma$. Note that $g'(N)$ is the slope of the mineral acreage supply curve, so ρ^M approaches the competitive case as the (linear) supply curve becomes more elastic, flattening to a horizontal line.

Greater dispersion of reservation rates reduces the elasticity of the mineral acreage supply curve, which in turn makes the firm less willing to increase the royalty rate. A low elasticity means that an increase in the royalty rate allows the firm to acquire too little additional acreage to compensate for increasing the rate for all inframarginal owners. Linearizing (3) and ignoring the zero lower bound yields

$$\ln(1 - \rho^M - \gamma) = -\ln(R) + \ln(1 + r) + \ln(c). \tag{5}$$

This formulation implies that a one percent increase in revenues causes a one percent decrease in the firm share $1 - \rho^M - \gamma$. Because $1 - \rho^M - \gamma$ is less than $1 - \rho^M$ in all but the perfectly elastic supply case, the share of the value of production going to the firm is larger when γ is larger. Thus, in the monosponistic case the steeper the mineral acreage supply curve, the less that resource abundance is passed to the mineral owner via a higher royalty rate.

B. Uncertainty

Suppose that both mineral owners and competitive firms are uncertain about the location and richness of oil and gas resources. The distribution of expected resources, *f(Q)*, is shared by all firms. Each firm receives a signal of expected resources, $\hat{Q}$, from this common distribution. Expected revenues for each firm are then a multiple of $\hat{Q}$, and the expected revenue distribution is a transformation of *f(Q)*. The firm with the highest expectation offers the highest royalty.

Given that it is higher than all other values, this highest expectation likely exceeds the true value, in which case the highest bidder has fallen under the "winner's curse" (Capen, Clapp, and Campbell 1971). Firms lower the offered royalty rate to avoid the winner's curse, a response similar to the incentive to lower bids in common value auctions (Milgrom and Weber 1982).[4]

The possibility of mineral owners capturing fewer rents in areas where uncertainty is greater is supported by research on public leases. Reece (1978) shows that the federal government could capture more rents from offshore leasing if it subsidized exploration and information provision prior to opening auctions for leasing. It is also consistent with what Hendricks and Porter (1988) found empirically for firms drilling offshore: firms earned positive profits on tracts adjacent to tracts that they already operated and which therefore gave them an information advantage in bidding for nearby tracts.

To summarize, there are multiple market imperfections that could attenuate the relationship between parcel endowments and royalty rates. At one extreme (perfect competition), a one percent increase in endowment leads to a one percent decrease in the share of production going to the energy firm (equation (3)). At another extreme (monopsony and an inelastic acreage supply curve), the endowment would have little to no effect on the share of production going to the firm. In the empirics, we estimate the relationship between endowments and the share of production going to the firm, thereby providing evidence as to how far either extreme is from reality.

IV. Data

[4] One important difference between the leasing of public and private minerals is that public minerals are commonly sold at auction while private minerals are leased through negotiation. We assume that negotiations are conducted at zero cost and may involve as many counterparties as there would be bidders in an auction, which simplifies the analysis.

Private data provider DrillingInfo furnished data on individual leases of privately-owned oil and gas rights around the United States.[5] DrillingInfo collects data on various aspects of oil and gas development, especially in areas where there is interest in development. Leasing data are collected from courthouse records and include the legal description of the tract, the address of the mineral owner, the year the lease was signed, and the royalty rate.

In cases where a parcel was leased several times, we use only the most recent lease. This reduces the potential for double-counting leases. Fractionation of mineral ownership means that several people may have ownership of the same acre and can require multiple lease instruments to fully lease. We are limited in our ability to identify which leases pertain to the same acre as opposed to being near one another but not overlapping. We make a conservative measure of the number of acres leased by counting only a single lease for the smallest area we can identify from legal descriptions; in general that area is 40 acres.

The lease data in most states include information about the mineral owner, allowing us to determine if she has an address in the same county and state as the lease. For these states we use this information to estimate the extent of local ownership, which we define as the percent of oil and gas rights owned by county residents.

The full set of leases includes nearly 1.8 million private mineral lease observations from 559 counties located in 16 states. Table 1 presents descriptive statistics of the lease data by state. The 16 states include most of the major producers among the 32 oil and gas producing states, and many of the top-producing counties are represented.[6] The share of total oil and gas produced (in barrels of oil equivalent converting at 6Mcf/bbl) in the sample counties varies from 66 to 75

[5] http://www.drillinginfo.com

[6] The states are: AR, CA, CO, KS, LA, MS, MT, ND, NM, OH, OK, PA, TX, UT, WV and WY. The largest producing states that are excluded are AK, which has very limited private mineral ownership, and AL, IL, IN and MI. A total of 1,097 counties produced oil or natural gas in 2011.

percent of total production over 2000-2011. Average acre-weighted royalty rates vary substantially across states, ranging from 0.126 to 0.215. Local ownership also varies considerably, with the lowest rates in western states with a history of extensive oil and gas development.

<< Insert Table 1 >>

To estimate the magnitude of royalty income, we aggregate the lease data to the play level (e.g. the Marcellus Shale). For the analysis of pass-through in the leasing market, we aggregate the lease data to the county.

Our analysis of pass-through uses the estimated ultimate recovery of the typical well in each county. Estimation of the ultimate recovery (described in a later section) uses county-level production and well data from 2005 to 2013. For production data, we add the years 2012 and 2013 to extend the USDA County-Level Oil and Gas Production dataset (USDA-ERS, 2014); well count data come from the provider of the leasing data, DrillingInfo. We focus on 2005-2013 because production growth in this period came almost entirely from shale wells. Shale thickness will therefore matter more for well productivity during this period than for prior periods. Moreover, our leasing data reflects leases signed in the 2000s, most of which occurred in areas with shale development and based on expectations about shale well ultimate recovery.

V. The Magnitude of Oil and Gas Royalties

Using the DrillingInfo leasing data, we estimate acre-weighted royalty rates at the county-level for six major shale plays located around the country (figure 1). Play-specific royalty rates (estimated by averaging across counties in each play) combined with production and price data from the Energy Information Administration allowed us to estimate total royalty income generated in 2014 from each shale play (see Appendix A.2 for data and estimation details). Using the share of leased acreage owned by county residents, we also estimate the total and per capita royalty income going to residents of the county where production occurs. To put the estimates in perspective, we also report the per capita value of government transfer income and farm program payments for each play.

<< Insert Figure 1 >>

Oil and gas production and payments in 2014 were substantial, but varied considerably across shale plays (Table 2). Together the six plays produced more than $213 billion in oil and gas in 2014, representing about 1.2 percent of U.S. GDP. The Permian accounted for the largest share, followed by the Eagle Ford and the Bakken, all of which primarily produce oil. Average royalty rates ranged from 13.2 (Marcellus) to 21.2 percent (Permian) while royalty income ranged from $2.5 billion (Niobrara) to $13 billion (Permian).

The share of local ownership sheds light on the royalty income captured by residents of the county where production occurs. Average local ownership shares ranged from 12 (Permian) to 55 percent (Marcellus), and local royalty income ranged from $0.54 (Haynesville) to $2.83 billion (Eagle Ford). This is an underestimate of the gross royalty income received by residents of each play because it does not capture the royalties of residents who hold mineral rights in other counties in the play, or as absentee owners in other plays.

To gain a sense of the economic importance of royalty income in the various regions, we normalize the estimates on a per capita basis. Much of the recent energy development has occurred in rural portions of the country (Brown et al., 2013). Particularly in sparsely populated areas, royalty income may account for a large share of personal income. Indeed, we find that in the Bakken and Eagle Ford plays, which cover sparsely populated areas, local royalty income per capita was between $2,900 and $4,200. In the more populated plays the measure ranged from $200 to $1,200 per capita. We note that these per capita measures are not an indication of how much royalty income the typical resident receives; undoubtedly, many local residents do not own subsurface rights and will therefore receive no royalty income.

Local royalty income is economically important when compared to government transfer income and federal farm payments per capita in 2012 for each play (Table 2). The Bureau of Economic Analysis defines transfer payments as transfers to persons for which no services were performed. The measure, which we use, includes retirement and disability insurance benefits, medical payments, unemployment insurance benefits, grants, and other payments. Federal farm payments data came from the 2012 Census of Agriculture and include crop insurance subsidies, Conservation Reserve Program payments, and commodity support payments. For all plays, royalty exceeds farm payments but not transfer receipts. Total royalty income per capita, however, greatly exceeds transfer receipts in the Bakken and Eagle Ford.

Because the six plays produced an estimated $213 billion in oil and gas, a one percentage point increase in royalty rate corresponds to $2.13 billion dollars. Assuming that energy companies would not curtail production in response to a higher royalty rate, the royalty income of mineral owners would increase by this amount if they had negotiated a one percentage point higher royalty rate. A one percentage point lower royalty rate would reduce local royalty income per capita between $20 and $250 across the different plays. To put this number in perspective, the reduction is similar to eliminating all of the farm payments in most of the plays. For example, Weber et al. (2013) found that energy payments, including oil and gas lease and royalty payments, to farm households were two times more concentrated in the Plains region compared to total farm payments.

<< Insert Table 2 >>

VI. Empirical Assessment of Pass-Through in the Leasing Market

We estimate pass-through in the leasing market by adapting the parcel-based theoretical predictions in (3) to a county-level analysis, focusing on the relationship between the ultimate recovery of the average county well and the royalty rate associated with the typical acre in the county. We take a county-level approach because production and ultimate recovery estimates are unavailable at the lease level.

If parcels vary across counties but not within them, the arguments in equation (3) can be replaced with county-level analogues. We assume that the average expected revenues for the average parcel in the county are given by expected prices (common to all firms) multiplied by the estimated ultimate recovery of the average well: $\bar{R}_c = p_t \cdot \bar{Q}_c$, where the subscript c refers to a specific county and $p_{c(t)}$ is the expected price when the leases in county c were signed. Replacing the terms in equation (3) with their county-level analogues yields

$$\ln(1 - \bar{\rho}_c) = -\ln(\bar{Q}_c) - \ln(p_t) + \ln(1 + r) + \ln(\bar{c}_c), \tag{6}$$

where $\bar{\rho}_c$ is the acre-weighted average royalty rate in county c.

A perfectly competitive market scenario implies that a one percent increase in the estimated ultimate recovery should lead to a one percent decrease in the share of the value of production going to the firm. If the royalty rate is 15 percent, a one percent increase in $\bar{Q}_c$ would imply a 0.85 percentage point decrease in the share captured by the firm. The share captured by the mineral owner–the royalty rate–would increase to 15.85 percent.

Equation (6) provides the basis for our econometric model. We account for the time varying market return on capital (*r*) and the price of oil and gas by calculating the average interest rate, price of oil, and price of gas at the time of lease signing. This is done by averaging values across time, where the weight on each year is given by the acre-weighted share of leases signed in county *c* in that year. Because the distribution of leases across time varies by county, so does the weighted price of oil and natural gas.

Shale play fixed effects and measures of historic development control for county-specific development costs c_c, which we do not observe. Shale play fixed effects control for average cost differences across plays. The historic development measure, which is defined as the percent of the county that ever had an oil and gas well as of 1980, controls for county-level cost differences associated with prior development.[7] Presumably areas with greater development have more oil and gas infrastructure and lower costs than areas with less development. The measure also helps control for general knowledge that mineral owners have of the oil and gas industry and therefore their sophistication in negotiating leases. Our base econometric model then becomes:

$$\ln(1-\bar{\rho}_c) = \beta \ln(\bar{Q}_c) + \alpha PD_c + \boldsymbol{P_{c(t)}}\boldsymbol{\delta} + \boldsymbol{Play_c}\boldsymbol{\gamma} + \varepsilon_c, \tag{7}$$

where *PD* is the percent of the county that had oil or gas development by 1980, $\boldsymbol{P_{c(t)}}$ is a vector of two variables (interest rates, prices), and $\boldsymbol{Play_c}$ is a vector of shale play dummies. The price is either the first purchase for crude oil (if an oil region) or the wellhead price of natural gas (if a natural gas region), both in terms of dollars per million British thermal units (MMBtu). In a

[7]We calculate this measure of historic development using the historic geospatial data on oil and gas wells provided by the U.S. Geologic Survey: http://pubs.usgs.gov/dds/dds-069/dds-069-q/text/cover.htm.

robustness check, we drop the interest rate and energy price variables and simply control for the share of leases in the county that were signed in different years.

A. Estimating the Ultimate Recovery for the Typical County Well

We need a way to measure $\bar{Q}_c$. Various methods have been used to estimate the ultimate recovery of the typical well, ranging from fitting a quadratic curve to the aggregate production of a field (Hubbert, 1956), to more recent well-based methods that estimate a decline curve for the typical well (Kaiser, 2012; Cox, 2013). We take a county-based approach that follows the spirit of the well-based decline curve methods.

Using county-level data on production and the age distribution of producing wells over time, we estimate how much an additional well increases total production on average. The increase depends on the well's age because productivity declines as wells age. Consider total production in a county *c* in year *t* as

$$Prod_{ct} = \sum_{a=1}^{A} \alpha_a (a\ yr\ wells_{\ ct} * thick_c) + \gamma_c + \eta_t + \varepsilon_{ct}, \tag{8}$$

where $a\ yr\ wells_{\ ct}$ is the number of active wells of age *a* in county *c* in year *t*, and γ_c and η_t are county and year fixed effects. The coefficient α_a gives the average production of an *a* year-old well from 1 meter of shale thickness. The county and year fixed effects help estimate the $\alpha_a$terms apart from additive time-invariant county characteristics or temporal shocks that affect the level of production.

We estimate (8) separately for each play, allowing an *a* year-old well to give different production for each meter of shale thickness in different plays. The majority of production from shale wells occurs in the first few years. As such we estimate the effect of wells of age 1, 2, 3, 4, and 5 year old well separately and lump wells 6 years and older into one category. We assume that wells 6 years and older produce for the equivalent of 4 more years. Thus, we estimate the ultimate recovery associated with 10 years of production. The estimated ultimate recovery of the typical well in the county, which we denote as EUR_c, is then calculated by summing the α coefficients multiplied by the county's shale thickness: $EUR_c = thick_c \cdot [(\sum_{a=1}^{5} \hat{\alpha}_a) + (4 \cdot \hat{\alpha}_{a>5})]$.[8]

The estimates of county-level EUR are shown in Figure 2. Our estimates of recovery compare well to those published by the Energy Information Administration (EIA). The EIA has published estimates of ultimate recovery for 106 of the 231 counties for which we have estimated the EUR (EIA, 2014b). It calculated county-level EURs using monthly well-level data to estimate parameters of a decline curve. The two sets of estimates are similar despite differences in methods. For the subset of counties where there is overlap, our average EUR is 1,485 BBtus compared to 1,419 for the EIA estimates (Table 3). Moreover, the two sets of estimates are highly correlated. Regressing the EIA estimate on our estimate and a constant shows that on average a 1 unit increase in our EUR increases the EIA estimate by 0.89 units, with a standard error of just 0.12 (Table A2).

<< Insert Figure 2 >>

<< Insert Table 3 >>

B. Estimation

We use our estimate of $\bar{Q}_c$, denoted as EUR_c, in equation (7), which yields the model that we estimate:

[8] The coefficients on the shale thickness and well age interactions are shown in table A1, which we use to estimate ultimate recovery of the typical county well.

$$\ln(1-\bar{\rho}_c) = \beta \ln(EUR_c) + \alpha PD_c + \boldsymbol{P_{c(t)}\delta} + \boldsymbol{Play_c\gamma} + \varepsilon_c. \tag{9}$$

The estimated ultimate recovery is undoubtedly measured with error because of unobserved heterogeneity in well productivity across counties. If ignored, this measurement error will cause us to underestimate pass through. The log of ultimate recovery can be written as $\ln(thick_c) + \ln\left((\sum_{a=1}^{5}\hat{\alpha}_a) + (4 \cdot \hat{\alpha}_{a>5})\right)$, which shows that the log of shale thickness is perfectly correlated with and cannot be used to address measurement error. Instead, we use the log of the average shale depth in the county as an instrument for $\ln(EUR_c)$. It is a natural choice for an instrument as it is correlated with well productivity–wells in deeper shales produce more gas (Ikonnikova et al. 2015; Marchand and Weber 2015). Moreover, shale depth should be uncorrelated with ε_{ct} given that it is time invariant and fully accounted for in the regression by the county fixed effect γ_c. As an alternative measure, we use the log of the average well productivity in a separate specification, because it should also be strongly correlated with ultimate recovery. Well productivity is calculated as the average production per well per year, averaged across the years 2005-2013.

We note that using shale depth versus well productivity as instruments could produce different local average treatment effects. Well depth may be correlated with higher productivity but also higher well costs. We would not expect that cost-driven differences in productivity pass-through to mineral owners because they would not necessarily correspond to differences in profitability. In this case, we might expect greater pass-through when instrumenting with productivity instead of depth.

With equation (9) as the second stage, our first-stage regression takes the form

$$\ln(EUR_c) = \pi_0 + \pi_1 \mathrm{z}_c + \pi_2 PD_c + \boldsymbol{P_{c(t)}\pi_3} + \boldsymbol{Play_c\pi_4} + \eta, \tag{10}$$

where z_c is either the logarithm of shale depth or the log of average well productivity in the county. Both instruments are strongly correlated with the estimated ultimate recovery, with an F statistic of 27.7 (depth) and 12.0 (productivity) (Table 4) The primary result is that a one percent increase in depth or well productivity is associated with a 0.77 or 0.19 percent increase in the estimated ultimate recovery.

<< Insert Table 4 >>

C. Pass-Through Estimates

Our IV estimates suggest limited pass-through of oil and gas endowments into royalty rates in our 231 shale counties. As expected with attenuation bias, the OLS estimates are smaller than the IV estimates, but even these are small. When using depth as an instrument for ultimate recovery, a 10 percent increase in recovery is associated with a 0.14 percent decrease in the share of the value of production going to the energy firm; when using the average well productivity, the effect is a 0.32 percent decrease (Table 5).

Doubling the EUR is equivalent to increasing $\ln(EUR_c)$ by 0.70 log points, which is associated with a roughly 1.0 to 2.2 percent decrease in the share of the value of production going to the firm (=0.70 x 1.4%, 0.70 x 3.2%). At the average royalty rate of 18 percent, this translates into a 1 to 2 percentage point decrease in the share going to the firm (e.g. 1 percentage point ≈ 0.01 x 82%). In turn, the share going to the mineral owner would increase by 1-2 percentage points.

Considering the other variables in the model, the play dummy variables indicate that there are large differences in average royalty rates across shale plays. All else constant, the largest share of production going to firms (and not to mineral owners) is in the Marcellus followed by the Fayetteville and Bakken shales. The coefficients on prices and interest rates are as predicted–negative for energy prices and positive for interest rates–however, the coefficients are small and statistically insignificant. Replacing these two variables with a set of variables indicating the share of leases signed in different years (i.e. the share signed in 2001, the share signed in 2002) has little effect on the coefficient on ultimate recovery.

<< Insert Table 5 >>

We re-estimate (8) using EIA estimates of ultimate recovery, denoted EUR_EIA_c, to see if the pass-through estimates are sensitive to the measure of ultimate recovery. Because a different sample of counties is used, we also estimate the model with our estimate, EUR_c. In both cases we instrument for the EUR using the log of the average well productivity, which is strongly correlated with both measures of the EUR on this subset of counties, with an F-stat of 16.5 and 22.7.

Using a different EUR measure gives an even smaller estimate of pass-through (Table 6). The OLS results are nearly identical for both EUR measures, but our measure gives a larger IV estimate than the EIA measure, -0.020 compared to -0.007. The estimates nonetheless fit in the range of the previous estimates using the full set of counties and our measure of the EUR.

<< Insert Table 6 >>

D. Implications for the Mineral Acreage Supply Curve

Equation 5 showed that in a monopsonistic environment, a one percent increase in the EUR decreases $1 - \rho_i^M - \gamma$ by one percent. We empirically estimated that a one percent increase in the EUR decreases $1-\rho_i^M$ by 0.032% at most. Combing the two expressions gives $1-\rho_i^M-\gamma=.032*(1-\rho_i^M)$. Using the sample average royalty rate of 18%, we can solve for the implied slope of the (linear) mineral acreage supply, yielding γ=0.79 (=1-0.18-[0.032×(1-0.18)]). In a monopsonistic scenario with price discrimination (see appendix 3) γ is the slope of the (linear) mineral acreage supply curve. Converting into an elasticity, a one percent increase in the royalty rate causes a 1.26% increase in the supply of mineral acreage (=1/0.79), indicating an elastic supply of private mineral acreage.

VII. What Explains Such Low Pass-Through?

Our finding of relatively low pass-through of oil and gas endowments to mineral owners is consistent with firms exercising market power in leasing markets and an upward-sloping mineral acreage supply curve. Yet, there may be other explanations for low pass-through such as sticky leases, well costs, and compensation through bonus payments.

A. Sticky Leases

Once signed, a mineral lease can remain in force for decades, with most leases written to remain in effect as long as production occurs.[9] The long life of the lease prevents the mineral owner from renegotiating the terms in response to changes in prices, technology, or other factors. In areas where firms leased land prior to widespread adoption of horizontal drilling and hydraulic fracturing, average royalty rates would remain those negotiated when expectations about the EUR were much lower. We would therefore expect less pass-through in areas with more active leases in 2000, prior to the technological shift.

[9] This provision, commonly known as "held by production," is studied in greater detail by Smith (2014).

We calculate the share of active leases signed in 2000 and estimate:

$$\ln(1-\bar{\rho}_c) = \beta_0 \ln(EUR_c) + \beta_1\big(SL_{c,2000} \cdot \ln(EUR_c)\big) + \alpha PD_c + \boldsymbol{P_{c(t)}\delta} + \boldsymbol{Play_c\gamma} + \varepsilon_c \quad (11)$$

where $SL_{c,2000}$ is the share of active leases in 2000 normalized by the sample average. If sticky leases account for the limited pass-through, $\beta_1$should be greater than zero and in turn cause β_0, which is negative, to be larger in absolute terms. To address measurement error, we instrument the new interaction term with the SL_c multiplied by the log of average well productivity. For the EUR and the interaction term, the Angrist-Pischke multivariate F-test statistics are 11 and 270.

The estimate of $\beta_1$is positive as expected (0.06), indicating less (or no) pass-through for leases signed in 2000. Nonetheless, pass-through on leases signed after 2000, indicated by the coefficient on β_0, is similar to what was estimated before (-0.03) (see Table A3). Thus, much production occurring under the terms of old leases does not explain our empirical finding, though it does indicate that sticky leases can reduce pass-through.

B. Deeper Wells Cost More to Drill

Another potential explanation for low pass-through is that greater depth and well productivity are correlated with greater development costs. One parcel, for example, may have twice the EUR as another parcel yet differences in costs could be such that competitive firms offer both mineral owners the same royalty rate, in which case low pass-through is confounded with heterogeneity in development costs. Data limitations prevent a thorough assessment of how accounting for costs would affect our estimates of pass-through. Kaiser and Yu (2015), however, provide a detailed analysis of drilling costs for the Haynesville Shale. Looking over the 2008-2012 period, they find that each kilometer of well depth, which is roughly one standard deviation for our average county, increases drilling cost by roughly 20 percent.

The higher costs associated with deeper wells may explain why using depth as an instrument for ultimate recovery provides smaller estimates of pass-through than when using well productivity as an instrument. Because depth and well productivity are correlated, we estimate pass-through using well productivity as the instrument for ultimate recovery while controlling for the average shale depth in the county. (Controlling for depth comes at the cost of a weaker first stage, with an F-stat on productivity of 5.3). The coefficient estimate on the EUR is larger than when controlling for depth (coef. -0.045, s.e. 0.020) (results not shown). However, this estimate still falls within the confidence interval based on the regression that excludes depth as a control variable. Thus, our qualitative finding of little pass-through does not change when accounting for one major source of variation in development costs across areas.

C. Bonus Payments and Royalty Rates

Some of the pass-through of greater oil and gas endowments may come through higher signing bonuses in addition to higher royalty rates. The extent to which mineral owners exchange higher royalty rates for larger bonus payments is an important question. We do not observe a bonus payment for most of our sample leases. Bonus payments are difficult to observe in part because they are not required to be recorded as part of the lease. However, our dataset allows us to observe bonus payments for a subset of leases—about 1.8 percent of the original sample. Using leases with royalty rates and bonus payments, a univariate linear regression of non-zero bonus payments on royalties yields an elasticity estimate of 0.53, with an r-squared of 0.90. This suggests that bonus payments are highest for parcels that firms view as favorable prospects, rather than as a substitute for a higher royalty rate.

Previously we estimated that a doubling of the EUR of the typical well led to a 1 to 2 percentage point increase in the royalty rate. At the average royalty rate of 18 percent, this translates into a 6 to 11 percent increase. Using the observed elasticity between bonus payments and royalty rates implies that bonus payments would have simultaneously increased by 3.2 to 5.8 percent (e.g. 6×0.53). With a mean observed bonus payment of $374 per acre, this increase in bonus payments represents a small increase in the share of production captured by the mineral owner and would therefore have little effect on our estimate of pass-through.

It is worth noting that some areas have much higher bonus payments than the average. For example, within our limited sample we found state averages as high as several thousand dollars per acre.[10] However, because royalty rates and bonus payments are positively correlated, we expect the present value of higher expected royalty payments to rise along with those of higher bonus payments.

VIII. Conclusion

The innovation-spurred growth in oil and gas production from shale formations resulted in the U.S. becoming the global leader in producing hydrocarbons. The six major U.S. shale plays produced more than $213 billion in oil and gas in 2014, generating $39 billion in private royalty payments. These payments are important and largely unexpected income shocks. Although royalty rates vary widely, from 13.2 percent in the Marcellus to 21.2 percent in the Permian, greater ultimate recovery of the typical county well translates into very small increases in the average royalty rate. Thus, even though one mineral owner owns twice as much oil and gas

[10] Several counties have mean bonus payments over $1,000 per acre. However, these counties represent a very small share of our observations. The median bonus payment we observe is $104, the 90th percentile is $900, and the 99th percentile is $12,000.

compared to another owner, both will receive a similar share of the value of production. Owners of more resources, of course, reap greater total royalties but their resource abundance allows them to negotiate only marginally better lease terms with extraction firms.

The limited pass-through of oil and gas abundance likely reflects a combination of institutional factors, uncertainty about new resources, and market power. Our analysis here is cross-sectional, but the dynamics of leasing markets are ripe for further work. Early in the development of a play, speculators and extraction firms bid on leases whose value is highly uncertain; later, firms spatially consolidate their acreage, causing unleased mineral owners to face an increasingly oligopolistic and even monopsonistic market for oil and gas rights. Both explanations are consistent with the nature of unconventional oil and gas development where new techniques unlocked resources of unknown value (Zuckerman 2013). Information asymmetries may exist between firms and mineral owners, but experience gained through repeated interactions may mitigate those effects. Such long-term experience may go a long way to explaining the higher prevailing royalty rates in long-producing regions like Texas, Louisiana, and New Mexico.

Information from early leases and wells may be a silver lining for mineral owners in areas where infrastructure or policy has delayed leasing, development, and royalty checks. The willingness of private owners to share exploration risk with firms may reduce the ultimate gains from mineral ownership, but it may help explain the relatively early development of unconventional resources in the U.S. relative to countries with public mineral ownership (Hefner 2014). Of course, if the delay pushes production into a period of lower prices, then the royalty owner will likely be worse off.

A perhaps further-reaching implication of market power in leasing markets is that less acreage is leased and potentially developed than would be in a more competitive market, inadvertently leaving more oil and gas in the ground and raising prices in the present relative to the future. However, our data do not allow us to assess this extensive margin, which could be another rewarding area for future research. Such effects would have important efficiency implications that extend beyond the distributional issues we focus on here.

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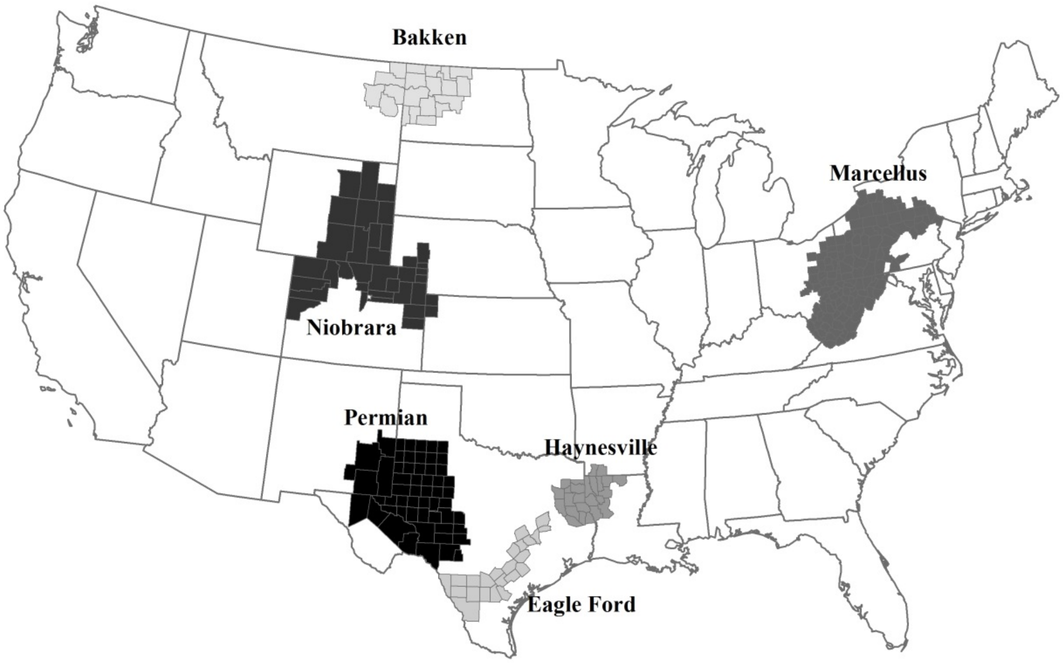

Figure 1. Major Shale Plays

Note: The major shale plays are those highlighted in the Energy Information Administration's drilling productivity reports. The Marcellus and Utica Shales are combined due to collocation of those shales across much of their respective ranges.

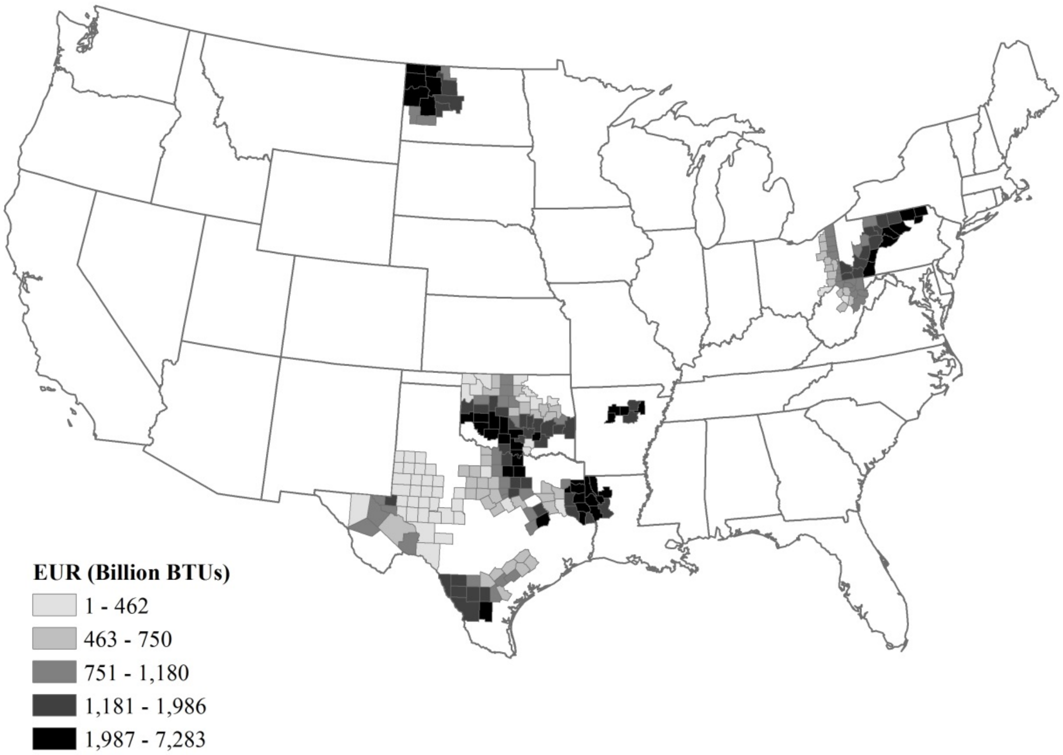

Figure 2. Estimates of Expected Ultimate Recovery of Oil and Natural Gas (in Billions of British Thermal Units)

Note: Figure 2 shows EUR estimates for shale areas where we have data to estimate ultimate recovery, which includes the Woodford Shale (Oklahoma) and the Barnett Shale (North Central Texas). Those areas are not shown in Figure 1 because they are not considered major shale plays by the Energy Information Administration.

Table 1. Summary of Oil and Gas Leases by State

State	Number of Leases	Number of Counties	Mean Royalty Rate	Mean In-County Ownership
AR	135,491	38	0.157	0.280
CA	59	3	0.166	0.032
CO	42,336	25	0.148	0.280
KS	81,972	38	0.137	0.432
LA	99,541	54	0.215	0.328
MS	105,624	42	0.184	0.182
MT	16,919	8	0.154	0.231
NM	20,177	3	0.211	0.217
ND	88,555	13	0.171	0.134
OH	31,175	32	0.126	0.670
OK	460,952	60	0.186	0.214
PA	50,094	26	0.135	0.576
TX	600,367	190	0.200	0.210
UT	1,574	1	0.166	0.109
WV	34,258	16	0.134	0.332
WY	6,733	10	0.153	0.219
Total	1,775,827	559	0.178	0.287

Note: Data are from DrillingInfo. The leases considered are all those in the DrillingInfo database and that pass our filters to prevent a duplication of acreage (e.g. multiple leases for the same acre). The in-county ownership share is the share of leased acreage owned by county residents divided by the total leased acreage. This statistic is calculated separately for AR, CA, KS, and MS, which are omitted from the econometric specifications due to insufficient leasing data.

Table 2. Estimates of Local and Total Royalty Income in Six Major Shale Plays, 2014

	Shale Play						
	Bakken	Eagle Ford	Haynesville	Marcellus	Niobrara	Permian	Total
Value of production ($ billion)[1]	36	57	12	30	17	61	213
Royalty rate[2]	0.168	0.203	0.205	0.132	0.144	0.212	
Royalty income ($ billion)	5.97	11.54	2.45	3.94	2.51	13.03	39.45
Local ownership share[2]	0.151	0.245	0.22	0.547	0.303	0.119	
Local royalty income ($ billion)	0.90	2.83	0.54	2.15	0.76	1.55	8.73
Population[3]	215,051	961,366	1,388,581	9,163,359	3,221,799	1,310,080	16,260,236
Royalty income per capita	27,770	12,008	1,764	429	780	9,946	
Local royalty income per capita	4,202	2,942	387	235	236	1,183	
Govt. transfers per capita[3,†]	6,455	6,712	8,345	9,146	5,652	6,997	
Federal farm payments per capita[4,‡]	587	33	10	9	44	186	

Data Sources: [1] Energy Information Administration (2014a). [2] Drilling Info. [3] Bureau of Economic Analysis, REIS. [4] USDA NASS, Census of Agriculture. Notes: † Government payments to individuals includes retirement and disability insurance benefits, medical payments (mainly Medicare and Medicaid), income maintenance benefits, unemployment insurance compensation, veterans benefits, and Federal grants and loans to students. ‡ Includes federal farm program payments such as commodity support, crop insurance, and conservation reserve payments.

Table 3. Average Estimated Ultimate Recovery (EUR) of the Typical County Well, By Shale Play, Billion BTUs

	EUR, All counties	EUR, EIA Counties	EUR_EIA, EIA Counties
Barnett	916	1,305	832
Bakken	2,124	2,218	976
Eagle Ford	1,077	1,020	932
Fayette	2,009	1,868	1,388
Haynesville	2,051	2,779	3,329
Marcellus	1,333	1,698	2,016
Permian	309	323	364
Woodford	1,482	-	-
All	1,276	1,485	1,419
Counties	231	106	106

Note: EUR refers to our EUR estimates based on county level geologic, production, and well data. The EUR_EIA measure is based on the Energy Information Administration's published estimates of ultimate recovery for 106 counties of the 231 counties for which we have estimated the EUR (EIA, 2014b).

Table 4. First Stage Regressions Relating Shale Depth and Well Productivity to Estimated Ultimate Recovery (EUR), Dep. Var. = ln(EUR)

	ln(EUR)	ln(EUR)
Ln(depth)	0.775***	
	(0.147)	
Ln(Productivity)		0.194***
		(0.056)
Ln(Price of energy)	0.134	-0.208
	(0.655)	(0.609)
Ln(Interest rate)	0.379	0.725
	(0.642)	(0.636)
Percent developed	-0.195	0.025
	(0.215)	(0.291)
Barnett	-0.190	-0.825
	(0.911)	(0.849)
Eagle Ford	-0.581**	-0.410*
	(0.260)	(0.249)
Fayetteville	1.009	-0.590
	(0.890)	(0.822)
Haynesville	-0.164	-0.335
	(0.902)	(0.845)
Marcellus	-0.042	-0.588
	(0.905)	(0.834)
Permian	-2.646***	-2.193***
	(0.348)	(0.331)
Woodford	-0.160	-0.686
	(0.931)	(0.886)
Intercept	0.734	5.238***
	(1.858)	(1.441)
	(2.774)	
Counties	231	231
Adjusted R^2	0.45	0.44
F-statistic on excluded instrument	27.7	12.0

Note: *** $p<0.01$, ** $p<0.05$, * $p<0.1$. Robust standard errors are in parentheses. For the shale play dummy variables, the excluded play is the Bakken. The estimated ultimate recovery is an estimate of how much oil and gas the typical county well would produce over its life.

Table 5. The Share of Production Captured by the Firm and Estimated Ultimate Recovery, Dep. Var. = ln(1-royalty rate)

	OLS	IV (Depth)	IV (Productivity)
Ln(EUR)	-0.006***	-0.014***	-0.032***
	(0.002)	(0.004)	(0.009)
Ln(Price of energy)	-0.008	-0.008	-0.006
	(0.015)	(0.015)	(0.021)
Ln(Interest rate)	0.011	0.015	0.025
	(0.017)	(0.016)	(0.022)
Percent developed	-0.002	-0.006	-0.014
	(0.005)	(0.005)	(0.009)
Barnett	-0.042*	-0.047**	-0.057*
	(0.022)	(0.021)	(0.030)
Eagle Ford	-0.048***	-0.051***	-0.058***
	(0.006)	(0.006)	(0.008)
Fayetteville	0.004	0.004	0.002
	(0.022)	(0.022)	(0.029)
Haynesville	-0.050**	-0.049**	-0.046
	(0.022)	(0.021)	(0.029)
Marcellus	0.032	0.028	0.020
	(0.022)	(0.021)	(0.029)
Permian	-0.072***	-0.091***	-0.133***
	(0.006)	(0.009)	(0.022)
Woodford	-0.032	-0.035	-0.040
	(0.022)	(0.021)	(0.030)
Intercept	-0.134***	-0.077**	0.047
	(0.030)	(0.036)	(0.081)
Counties	231	231	231
Adjusted R^2	0.84	0.80	0.47

Note: *** $p<0.01$, ** $p<0.05$, * $p<0.1$. Robust standard errors are in parentheses. For the shale play dummy variables, the excluded play is the Bakken. The estimated ultimate recovery (EUR) is an estimate of how much oil and gas the typical county well would produce over its life. The second column is from instrumenting the log of the EUR with the log of shale depth; the third column is from using the log of average well productivity as the instrument.

Table 6. The Share of Production Captured by the Firm and Various Measures of Ultimate Recovery, Dep. Var. = ln(1-royalty rate)

	OLS (EUR)	OLS (EUR_EIA)	IV (EUR)	IV (EUR_EIA)
Ln(EUR)	-0.003		-0.018***	
	(0.002)		(0.006)	
Ln(EUR_EIA)		-0.004***		-0.006***
		(0.001)		(0.002)
Ln(Price of energy)	-0.011	-0.011	0.001	-0.010
	(0.017)	(0.017)	(0.018)	(0.017)
Ln(Interest rate)	0.017	0.014	0.024	0.013
	(0.015)	(0.015)	(0.015)	(0.015)
Percent developed	0.001	-0.002	-0.003	-0.004
	(0.006)	(0.006)	(0.007)	(0.006)
Barnett	-0.052**	-0.050*	-0.040	-0.048*
	(0.026)	(0.027)	(0.025)	(0.026)
Eagle Ford	-0.042***	-0.039***	-0.051***	-0.038***
	(0.007)	(0.007)	(0.008)	(0.006)
Fayetteville	-0.001	0.003	0.011	0.006
	(0.023)	(0.024)	(0.024)	(0.023)
Haynesville	-0.066***	-0.061**	-0.043	-0.055**
	(0.026)	(0.026)	(0.027)	(0.026)
Marcellus	0.029	0.033	0.039*	0.036
	(0.023)	(0.024)	(0.023)	(0.023)
Permian	-0.077***	-0.073***	-0.108***	-0.074***
	(0.007)	(0.005)	(0.016)	(0.005)
Intercept	-0.153***	-0.147***	-0.081*	-0.135***
	(0.044)	(0.045)	(0.049)	(0.043)
Counties	106	106	106	106
Adjusted R^2	0.91	0.92	0.87	0.91

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parentheses. For the shale play dummy variables, the excluded play is the Bakken. The estimated ultimate recovery (EUR) is an estimate of how much oil and gas the typical county well would produce over its life. EUR refers to our EUR estimates; EUR_EIA refers to those published by the Energy Information Administration. The results in the third and fourth columns column are from instrumenting the log of the EUR with the log of average well productivity.

Appendix

1. Sequential versus Simultaneous Leasing by a Monopsonist

In the text we only consider the behavior of a monopsonist who simultaneously offers a uniform royalty rate to all mineral owners. Under this framework the monopsonist chooses the number of leases by maximizing the following expression:

$$\max_N \pi = N[(1-\rho(N))R-(1+r)c] \quad s.t.\, \rho(\mathrm{N})\mathrm{R} \geq g(N)\, \forall N$$

Derivation of the first order conditions gives the optimal royalty rate given by the firm:

$$\frac{\partial \pi}{\partial N} = -\rho'(N)NR + [(1-\rho(N)R-(1+r)c] = 0$$

$$(1-(\rho(N))R - R\rho'(N)N = (1+r)c$$

$$R(1-\rho(N)-\rho'(N)N) = (1+r)c$$

$$1-\rho(N)-\rho'(N)N = \frac{(1+r)c}{R}$$

$$\rho(N) = 1-\rho'(N)N - \tfrac{(1+r)c}{R}. \qquad \text{(A.1)}$$

If the monopsonist can lease sequentially and perfectly discriminate between mineral owners, then it will capture additional rents. This is because inframarginal mineral owners will receive a royalty rate determined by their reservation rate, nothing higher. The N^{th} royalty owner, with a reservation rate slightly higher than the N-1^{th} owner, captures a slightly higher share of the value of production, as given by:

$$\rho^D = 1-\rho'(N) - \tfrac{(1+r)c}{R}, \qquad \text{(A.2)}$$

where parcels are homogeneous and $\rho'(N) \neq 0$, for N>1, $\rho^D > \rho^M$. The difference between A.1 and A.2 depends on the size of the leasing market, N. For larger N, the monopsonist faces a higher cost of acquiring more land because it will have to pay the higher royalty rate to many more parcels. In our empirical analysis, we focus on mean royalty rates. When the acreage supply function is linear, the firm pays a lower average royalty rate under sequential rather than simultaneous leasing, and the firm captures a greater surplus. If parcels vary in resource abundance or costs, and particularly if reservation royalty rates are less than perfectly correlated with potential returns, the firm can capture more rents through royalty rate discrimination.

Our modeling has avoided the possibility of differences in information between mineral owners and firms and focused instead on market power. Asymmetric information may be considered the root cause of market power in the leasing market. Greater information could affect outcomes in the perfectly competitive scenario if the information affects reservation royalty rates of mineral owners. For example, if greater information increases reservation rates, Equation (1) will still hold with equality but it will do so at a lower N, thereby reducing the number of parcels that are developed. In the monopsonistic scenarios, greater information has a potentially counterintuitive effect. If information increases the dispersion of reservation royalty rates, it will increase the elasticity of the mineral acreage supply curve. In doing so, it increases the distortion introduced by imperfect competition. In this interpretation, all oil and gas firms benefit from better information than mineral owners.

2. Data and Calculations for Royalty Income Estimates

Price and production data by shale play comes from the Energy Information Administration's drilling productivity reports. We use average daily production in each month to calculate total production for the year (EIA 2014a). For oil prices, we use EIA's state-level first purchase price of oil (Jan. 14 to Dec. 14). Production-weighted averages of prices were used in cases where plays covered multiple states. EIA wellhead prices of natural gas by state were only available through 2010, so wellhead prices in 2014 were projected for each play by adjusting the Henry Hub spot price in 2014 by the average difference between it and state-level wellhead prices in 2009 and 2010. Value of production estimates were generated by summing the product of price and quantity of oil and gas in each play.

Table A1. Shale Thickness and Oil and Gas Production, Dep. Var. = Total Oil and Gas Production (Billion Btus)

	Bakken	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Permian	Woodford
Thick x 1 yr wells	144***	110***	72***	270***	108***	151**	8**	206**
	(11)	(24)	(21)	(72)	(21)	(72)	(4)	(102)
Thick x 2 yr wells	77***	136***	34	351*	210***	102**	22***	-13
	(28)	(14)	(83)	(194)	(64)	(50)	(5)	(60)
Thick x 3 yr wells	142***	91***	60	78	168**	34	25***	61
	(18)	(25)	(90)	(60)	(83)	(25)	(8)	(37)
Thick x 4 yr wells	15	70***	264	337***	73**	22	24***	20
	(29)	(4)	(181)	(117)	(34)	(18)	(6)	(41)
Thick x 5 yr wells	141***	112***	-116**	7	135***	129**	13	177*
	(26)	(31)	(55)	(232)	(41)	(56)	(11)	(106)
Thick x wells gt 5 yrs	27	62***	50***	303**	73***	33	8***	29**
	(34)	(11)	(14)	(136)	(26)	(22)	(3)	(15)
Observations	120	328	192	48	216	712	296	406
Adjusted R^2	0.986	0.895	0.550	0.824	0.625	0.273	0.560	0.168

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors clustered by county are in parentheses. The results are from estimating the county fixed effects model represented by equation (12) and using data from 2005 to 2013. Shale thickness is in meters.

Table A2. The EIA Estimated Ultimate Recover and Our Measure of Ultimate Recovery (Billion Btus), Dep. Var. = EUR_EIA

	EUR_EIA
EUR	0.895***
	(0.123)
Intercept	90
	(133)
Counties	106

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parentheses. EUR refers to our EUR estimates; EUR_EIA refers to those published by the Energy Information Administration.

Table A3. Sticky Leases and Pass Through, Dep. Var. = ln(1-royalty rate)

	IV
Ln(EUR)	-0.032***
	(0.009)
ln(EUR) x Share 2000	0.061*
	(0.032)
Ln(Price of energy)	-0.005
	(0.021)
Ln(Interest rate)	0.024
	(0.022)
Percent developed	-0.014
	(0.009)
Barnett	-0.056*
	(0.030)
Eagle Ford	-0.058***
	(0.008)
Fayetteville	0.003
	(0.029)
Haynesville	-0.045
	(0.029)
Marcellus	0.021
	(0.030)
Permian	-0.133***
	(0.022)
Woodford	-0.039
	(0.030)
Intercept	0.044
	(0.082)
Counties	231
Adjusted R^2	0.468

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parentheses. The *Share 2000* is the share of active leases signed in the year 2000. The estimated ultimate recovery (EUR) is instrumented by average well productivity. The interaction is instrumented by the interaction between well productivity and *Share 2000*.