Estimates of U.S. Private Oil and Natural Gas Royalties

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I. Introduction

The United States is the only country in the world with widespread private ownership of minerals. This private ownership has helped make many citizens rich throughout the country's history from strikes of precious metals and other minerals, as well as hydrocarbon resources. As the United States enjoys a Renaissance of oil production amidst the current high price environment, the ownership of oil and natural gas resources has reemerged as a critical economic force. Although private oil and gas ownership is acknowledged as an important contributor to innovation in development of unconventional resources and the technologies used to produce them (Yergin 2011), little is known about the aggregate value of private mineral interests. Usually private minerals are leased to developers in exchange for a royalty paid on the basis of gross production revenue as oil and natural gas are extracted. In this paper we estimate aggregate private oil and gas royalty incomes in recent years.

Our estimates indicate that in 2012 an estimated 77 percent of oil production from onshore sources in the lower 48 states was from private minerals.[1] We estimate that natural gas from privately owned minerals comprised a comparable 81 percent of production from private onshore sources in 2012. These are big pieces of an extremely large pie. We estimate that in

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[1] All of the estimates we report below are based on data from the lower 48 states. Hawaii has no commercial production of oil and gas. Due to its particular land claim history, Alaska has very little private oil and gas production.

2012 total gross revenue from oil and natural gas production exceeded $220 billion for all U.S. onshore production. This represents about 1 percent of U.S. GDP.

We estimate the value of production from private minerals to be about $161 billion in 2012, of which private royalty owners were paid $22 billion in gross compensation for their mineral property. At the state level, the largest private oil and gas royalties were received (in descending order) from production in Texas, California, Louisiana, and Oklahoma. These are states with a high proportion of private minerals, and all are among the largest-producing states. Expressing private royalties as a proportion of total personal income in a state, a slightly different set of states is revealed to be heavily dependent on private oil and gas royalty income: North Dakota, Wyoming, Oklahoma, and Texas.

Our analysis and estimates provide valuable complements to two recently released studies, one of which (Weber et al., 2013) estimates payments from natural gas production and wind energy to farm operators to be $2.3 billion in 2011. The second study (IHS 2013) estimates the total contribution to GDP of unconventional oil and gas resources at $284 billion in 2012. The fact that our estimates lie between these other estimates is appropriate, given the different objectives of the studies.

The leading role of the United States in worldwide oil and gas production and technology development is often attributed to the institution of private ownership that provides companies with willing partners for development of resources (Wang and Krupnick, 2013).[2]

[2] In 2013 the United States became the world's leading producer of natural gas, and it remains the third-largest producer of oil (after Saudi Arabia and Russia). However, the growth rate of U.S. oil production has led some (e.g., Gold and Gilbert, 2013) to predict that the U.S. could soon become the world's largest producer of oil and gas.

The approach we adopt to estimate revenues from privately owned oil and natural gas production pursue is to start with aggregate annual U.S. oil and natural gas production and revenue data. We then net out production and revenues from federal and state-owned minerals and attribute the remaining revenue and production values to privately owned minerals. Standard leasing arrangements call for the revenues from private production to be divided between the companies that extract the minerals and the individuals who own the mineral rights. The final step of our process is to estimate the royalty income received by the latter group.

Specific issues that arise with these data are discussed in detail below to allow the reader to understand the strengths and weaknesses of our estimates. Briefly, there are two important data shortcomings in our process. First, although we were able to obtain data from some states regarding production and revenues from their state-owned mineral rights, other states were not able to provide us with this information. For the latter states, we use information from similar states to estimate production and revenues from state-owned minerals. Our estimates of private production as the residual from aggregate production after subtracting production from federal- and state-owned mineral rights are almost certainly less accurate for these states than for the states that provided us with information on production from their lands. Second, even in the former states, where we believe our estimates of production and revenues from private oil and natural gas mineral rights are good, there is very little information available on the share of those values that goes to the individual owners of those private mineral rights. We consider several methods for imputing average royalty rates, and ultimately employ two methods for estimating the share of gross revenues received by royalty owners.

In the next section, we present background information that provides context for the estimates that follow. We develop and present our estimates of production and value for private

minerals in the third section. In the fourth section, we discuss our results and suggest an agenda for further research. A fifth section concludes.

II. Aggregate Production

Thanks largely to a confluence of technological advances, the production of both oil and natural gas in the United States have increased in recent years. This increase extends a longer trend of growth for natural gas, but for oil the increase has reversed decades of declining production. A key source of the expansion has been unconventional resources such as shale, tight sands, and coalbed methane. First with natural gas, but increasingly with oil as well, these resources have replaced depleted conventional deposits in reserves (EIA). The technological advances themselves have been known for some time (Bohi, 1998), but the application of advanced seismography, horizontal drilling, and hydraulic fracturing has unlocked substantial productivity gains.

As production has expanded, oil and natural gas prices have reacted differently. Although it is produced in different grades, oil is a fungible commodity whose price is determined in a global marketplace. Despite rising U.S. production and decreasing consumption in recent years, the price of oil has remained strong. In contrast, though natural gas can be traded with contiguous neighbors in Canada and Mexico, access to the global market is limited by the absence of liquefied natural gas export facilities in the United States. As a result, the U.S. natural gas market is largely insulated from the world, and starkly different price dynamics have prevailed in the U.S. market than elsewhere around the world.

The number of producing oil and gas wells is affected by two important factors. The first is new wells drilled; the second column in table 1 reflects the active drilling of new oil and gas wells during the past decade. The second factor is the price environment for the products. When prices are relatively high, marginal wells are likely to be brought into production.

Table 1 also provides information on oil and natural gas production and prices over the decade from 2003 to 2012. As can be seen, after hovering around 1,100 MM bbls for most of the decade, oil production jumped to 1,700 MM bbls in 2012, an increase of about 50 percent. Natural gas production increased steadily over the decade, and as with oil, the 2012 level of production was about 50 percent higher than in 2003. Oil prices in 2011 and 2012 were more than triple the price levels in 2003, whereas natural gas prices have fallen from a high of almost $8 per unit to less than $3 per unit in 2012.[3] These aggregate annual averages mask price dispersion from a broad range of sources including differences in grades of crude, and in spatial basis for both oil and gas, as well as from temporal factors. The values reported in table 1 are benchmark averages; the oil price is the West Texas Intermediate price at Cushing, OK, and the natural gas price is a U.S. wellhead average. The table also reports real prices, using the producers' price index less food and energy with 2007 as a base year.

Table 1: Annual Oil and Natural Gas Wells, Production, and Prices

Year	All Producing Wells	New Wells (Oil & Gas, excl. Dry)	Nominal WTI Spot Price $/bbl (annual avg)	Nominal HH Spot Price $/Mcf (annual avg)	Real WTI Spot Price $/bbl (annual avg)	Real HH Spot Price $/Mcf (annual avg)	Oil Production (MM bbls)	Gas Production (Bcf)
2003	755,618	28,851	28.47	4.88	26.50	4.54	1,114	15,568
2004	773,657	32,975	37.63	5.46	35.54	5.16	1,094	15,548
2005	750,982	39,369	51.02	7.33	49.35	7.09	1,084	15,795

[3] Historically, oil and natural gas prices have been relatively highly correlated. In recent years, however, observers have puzzled over the fundamentally different dynamics of these prices. E.g., see Ramberg and Parsons (2012).

2006	781,327	46,223	60.22	6.39	59.10	6.27	1,089	16,508
2007	804,130	46,090	67.04	6.25	67.04	6.25	1,097	17,398
2008	851,204	48,879	94.72	7.97	97.94	8.24	1,133	18,798
2009	824,847	29,278	56.65	3.67	60.08	3.89	1,126	19,219
2010		32,449	75.04	4.48	80.56	4.81	1,193	20,137
2011		32,688	95.35	3.95	104.84	4.34	1,358	22,224
2012			94.11	2.66	106.16	3.00	1,705	23,776

Notes: All wells: EIA; new wells: IPAA; production and prices, EIA.

Individual mineral owners are likely to care much more about the local product price than about a national benchmark price. Some regions have continuous price data from deep markets, whereas other regions (where markets are thin) have lower quality data. In our analysis below, we rely on the fact that the U.S. oil and natural gas markets are generally highly integrated, which means that prices move together in different market areas (Bachmeier and Griffin, 2006).

From the perspective of the royalty owner, gross production revenue is the critical statistic to track. Hydrocarbon deposits sometimes contain oil and gas in associated deposits. In other cases, oil or natural gas is found by itself. Depending on lease terms, a royalty owner might benefit from the sale of other products.[4] Unfortunately, the fragmentation of markets for these products makes analysis difficult so we exclude them from the analysis.

Oil revenues were more than five times higher in 2012 than in 2003, but natural gas revenues were about 17 percent lower. Because domestically produced natural gas does not have access to foreign markets, the revenue decline is largely due to the lower prices resulting from the increased volume of gas produced. The sum of oil and natural gas revenues was roughly twice as high in 2012 as in 2003, illustrating that the increase in oil revenue more than offset the decrease for gas. Natural gas revenues were greater than oil revenues for the first eight years in the decade, but were smaller during the final two years.

[4] Included in this category are potentially valuable associated products such as natural gas liquids, and gases including helium, carbon dioxide, and nitrogen.

The sum of onshore oil and natural gas revenues in 2012 was $223.7 billion. To put these revenues in perspective, they represented about 1.4 percent of aggregate U.S. Gross Domestic Product (GDP) in 2012. This percentage might seem small, but these revenues were greater than the GDP of 30 individual states in 2012.

Oil and Gas Leasing

In the United States, mineral rights are owned by the federal government, individual states, sovereign tribal governments, and private landowners.[5] The division among these four groups varies substantially between states. While federal mineral ownership accounts for 39.8 percent of total land area in the lower 48 states, the share varies widely between states. Important producing states such as Texas have little federal or state mineral ownership. In other important producing states such as Wyoming, state and federal mineral ownership are at least as important as private ownership. Oil and gas companies seek access to resources from all types of mineral ownership.

Regardless of the type of mineral owner, most oil and gas production occurs under the provisions of oil and gas leases as opposed to direct mineral ownership by the operator. Leases allow a development company to minimize capital investment and share risk with the owner of the mineral rights. At the same time, the technical sophistication required for modern oil and natural gas production precludes most mineral owners from developing their own resources. The leasing arrangement is a mutually beneficial partnership between mineral owners and development companies. At the time a lease is signed, a "bonus" payment is typically made by

[5]Definitive data on production from tribally-controlled minerals is not available. Some mineral production revenues on Indian reservations are held in trust by the federal government—those revenues are included in the federal production statistics reported here. Non-federal tribal revenues are included in the private royalty amounts.

the development company. The primary compensation to the mineral owner on a producing lease, however, is in the form of the royalty payment.

The royalty rate (as well as the bonus payment) varies depending on the perceived likelihood that marketable quantities will be found on a tract, the cost of bringing those quantities to market, and other factors. Active markets in private and public leases exist in many states, for both new and existing leases. Leases can be remarkably long-lived, regularly outlasting their creators, in which case the mineral interests are usually conveyed to subsequent generations, leading to concerns about the fractionation of mineral interests. Moreover, mineral interests are sometimes held separately from related real property, such as the surface under which the minerals are located.

Production revenues from oil and natural gas are distributed in accordance with the provisions of the lease that governs the production. Typically, the mineral owner is due a percentage of the gross revenues with this percentage being an important subject of negotiation when the lease is signed. This percentage is referred to as the royalty interest. Historically, royalty interests have been around one-eighth, and federal royalty interests still are one-eighth for onshore leases. In the private market, however, royalties of one-sixth, three-sixteenths, one-fifth, and even higher shares of production are common. The royalty rates on state mineral leases also vary. Private mineral owners generally seek as high a royalty as they can in exchange for signing a lease. The balance of production revenues accrues to the companies that extract oil and natural gas from the ground. This share is referred to as the working interest.[6] Companies,

[6] Mineral owners can elect to be working interest partners of oil and gas companies. Most do not, however, because the risk that the working interest partner must bear is substantial

who must pay the costs associated with the development, including both production and lifting costs, view the royalty payments to mineral owners as a cost.

Production from federal minerals is governed by a standard oil and gas lease that closely resembles private leases. Some income is received from bonus and rental payments—but these have only comprised about 10-15 percent of gross receipts from federal leases in recent years. Federal royalty revenues can therefore have important fiscal implications. The gross revenue royalty is one-eighth (12.5 percent) for onshore leases. For both oil and natural gas, the average royalty rate paid on producing federal leases for the decade from 2003 – 2012 was about 11 percent. The fact that the average is below the standard 12.5 percent royalty rate is due in part to some production from very old leases with lower royalty rates.[7]

Production from Federal Minerals

Federal mineral production is an important policy topic in its own right (Boskin et al., 1985). Figure 1 shows the production amounts and values for natural gas produced from federally-owned onshore minerals (excluding Alaska) for the decade from 2003 – 2012. In addition to the aggregate across all states, the figure shows the contribution of major producing states: Wyoming, New Mexico, and Colorado.

[7] For example, there are active federal leases issued under the original terms of the 1920 Mineral Leasing Act that pay a 5 percent royalty. Since 1940 all onshore federal leases have included a royalty rate of at least 12.5 percent.

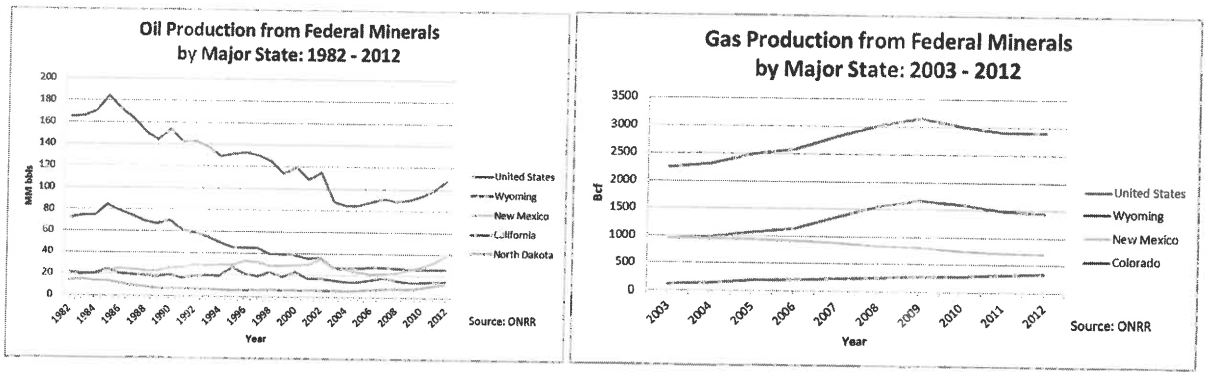


Figure 1: Oil and Gas Production from Federal Minerals, by Major State

A slightly longer series is available for oil production from onshore federal minerals. This series is also shown in figure 1. Major producing states are broken out in addition to the aggregate (excluding Alaska). The trend in federal oil production is quite different from that in gas production. The long-term decline in oil production is pronounced, though recent years have seen production stabilize and even inch upwards.

Production from State Minerals

Individual states also own minerals and lease them to developers in exchange for a royalty. States differ in how much state land was initially received from the federal government (Public Land Statistics), in how much land has been retained by state governments since the initial grants were made, and in how active each state is in developing oil and gas resources from retained lands. States use leases similar to federal and private leases, and the revenues received from these are often dedicated to specific purposes; support of public schools and other institutions (such as prisons and hospitals) is common. The nine states that were able to provide us with data on oil and natural gas production from state lands are listed in table 2. In addition to the indicating the states and years of data that are available, the average shares of total statewide

production of oil and gas attributable to state-owned minerals are included to provide some context for the importance of state minerals across states.

Table 2: State Mineral Production Data Acquired, with Average Annual Share of Total Oil and Gas Production

State	Years	Average Share of Oil (percent)	Average Share of Gas (percent)
Colorado	2011 – 2012	4.44	9.35
Louisiana	1967 – 2012	30.66	13.55
Michigan	1995 – 2012	20.42	31.94
Montana	2004 - 2011	5.41	6.53
New Mexico	2000 – 2012	23.97	12.99
North Dakota	2007 – 2012	27.04	26.10
Texas	1990 – 2012	5.34	3.43
Utah	2009 – 2012	0.63	2.25
Wyoming	2011 – 2012	7.36	6.65

Note: The numbers in this table are based on the responses received from our requests of each of the 17 largest producing states.

Focusing on the past decade, only five states have complete state mineral production reports. For the other four states with partial records, we interpolate attributing a constant proportion of production from state-owned minerals over time. There are eight other states that are important producers of oil and natural gas—Arkansas, California, Kansas, Ohio, Oklahoma, Mississippi, Pennsylvania, and West Virginia.[8]

. To estimate production shares from state-owned lands for these eight states, we use a weighted average of two groups of states. For the eastern and older states, we use a production-weighted average of Louisiana, Michigan, and Texas. For western and more recently-admitted

[8] There are also 13 additional states where some crude oil is produced and 15 additional states that produce some natural gas.

states, we use an average of the other six states in table 2 to construct an estimate of state mineral production.[9]

During the past decade, oil production from state minerals has followed the trend in aggregate U.S. production described above. One state with a noticeable increase in total production is North Dakota, which has experienced a dramatic increase in oil production thanks to development of the Bakken shale formation. The reported increase in production from North Dakota (since 2007), along with the increase in production from Texas, represents a majority of the estimated increase for the country as a whole.

Natural gas production from state-owned lands has followed a different trajectory over the past decade. States managing mineral resources to fund public schools might be more inclined to promote oil development in preference to gas due to the stronger price environment for oil. Large gas-producing states including Texas, Louisiana, and New Mexico continue to produce substantial quantities from state-owned minerals.

Production from Private Minerals

By subtracting reported federal production and our estimates of state minerals production from reported total production, we generate an estimate of oil and natural gas production from private minerals. This is an important step in deriving private royalty income estimates, which is our primary objective in this paper. Figure 2 illustrates the importance, for both oil and natural gas, of private minerals, which comprised between 70 and 80 percent of aggregate U.S. production over the decade shown. Despite increases in state production in North Dakota, it is

[9] The respective percentages are 21.39 for oil and 17.83 for gas in the western states (California, Kansas, and Oklahoma), and 20.16 for oil and 14.48 for gas in the eastern states (Arkansas, Mississippi, Ohio, Pennsylvania, and West Virginia).

evident that the recent increase in U.S. oil production is primarily attributable to the development and increased production of oil from privately owned minerals. The economic benefit of that increased production is shared by private mineral owners. In 2012, our estimates suggest that the private mineral share of oil production is 76.7 percent.

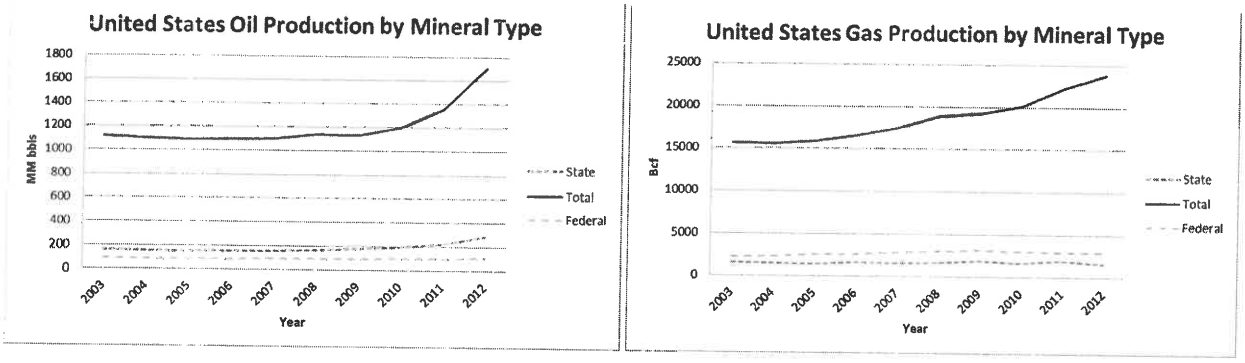


Figure 2: United States Oil and Natural Gas Production by Mineral Ownership Type

Our previous discussion of oil and natural gas production and prices highlights the differences between the two products. Figure 1 shows the share of natural gas production attributable to private minerals. Like oil, production of natural gas from privately owned mineral rights is critical; in 2012, our estimate of the private mineral share is 81.2 percent of gas production. The expansion in natural gas production has been almost entirely attributable to private mineral development. This result is not surprising given the importance of Eastern shale resources.

III. Private Mineral Gross Production Revenue and Royalty Income

Gross Production Revenues

To calculate private gross production revenues, we multiply estimated private production volumes by the reported benchmark prices. The reported benchmark price for oil is the first purchase price as reported by the U.S. Energy Information Administration (EIA). This price is reported annually for each state and is calculated as a volume-weighted average of observed transaction prices at the first sale of oil. In any state, it is likely that prices differ by location, producer, and time of year. Lacking information on such differences, we assign the average annual price to each unit of production in the corresponding year. The benchmark price for natural gas is the state-level wellhead price. Estimates for these prices are not available at the state level after 2010. Accordingly, we develop estimates for the 2011 and 2012 natural gas prices.[10]

Table 3 reports our estimates of aggregate gross revenue from private production for all states over the years 2003 – 2012. Oil and gas are reported separately, and then combined in the rightmost column. The revenue figures are reported in billions of nominal, or not inflation-corrected, dollars.

Table 3: Gross Production Revenues from Private Minerals, United States 2003 - 2012

Year	Nominal Oil Revenue	Nominal Gas Revenue	Combined Nominal Revenue	Real Oil Revenue	Real Gas Revenue	Combined Real Revenue
2003	24.48	57.21	81.69	22.78	53.25	76.03
2004	32.06	63.87	95.93	30.28	60.32	90.59
2005	43.29	86.79	130.08	41.87	83.95	125.82
2006	50.75	77.98	128.74	49.81	76.53	126.34
2007	57.03	81.19	138.22	57.03	81.19	138.22
2008	82.93	112.22	195.14	85.75	116.04	201.79
2009	48.65	52.05	100.69	51.60	55.20	106.80
2010	67.83	69.07	136.89	72.82	74.15	146.97
2011	98.71	68.6	167.32	108.54	75.43	183.97

[10] Because basis differentials between annual state-level wellhead prices are likely to be relatively constant, for each state, we regress annual state prices prior to 2011 on a constant and the U.S. benchmark price. We then use the estimated parameters to predict annual state-level wellhead prices for 2011 and 2012.

2012	123.01	38.61	161.62	138.76	43.55	182.31

Note: Figures are in billion nominal dollars.

Given that oil and gas leases typically stipulate that the mineral owner receives a royalty based on the gross revenue from production, the estimates in table 3 provide the basis for an estimate of gross private royalty income. Figure 3 shows annual estimates of this income for a range of common royalty rates: one-eighth (12.5%), one-sixth (16.67%), and three-sixteenths (18.75%). As one would expect, the risk sharing inherent in a royalty contract means that royalty payments fluctuate with both production and prices. Private mineral owners have benefitted from increased production of both oil and natural gas in recent years. Increasing oil prices have benefitted oil royalty owners, whereas recent decreases in natural gas prices have been to the detriment of gas royalty owners. For the decade shown in figure 2, our simple calculations yield estimates of annual gross royalty income that range from $10 to $35 billion. These estimates are clearly sensitive to the assumption we make about the prevailing royalty rate.

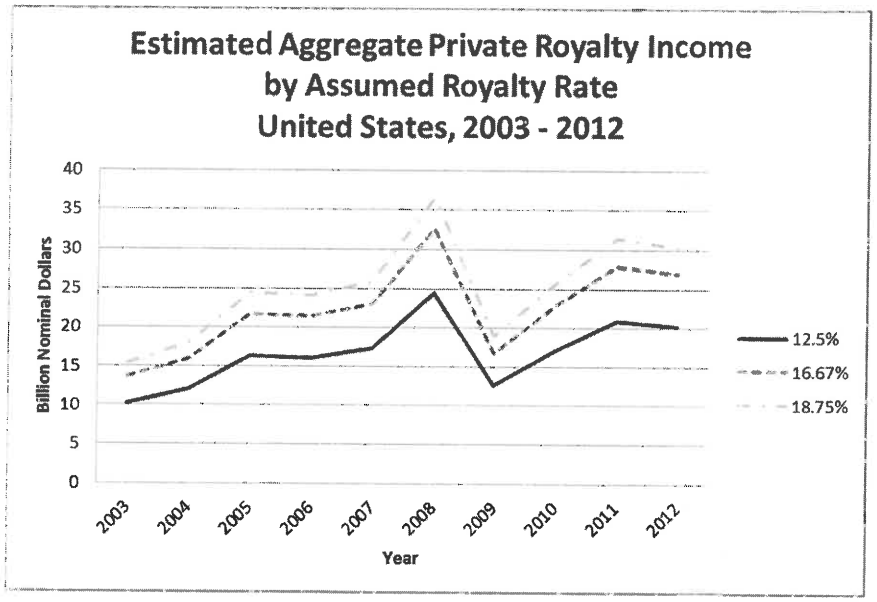


Figure 3: Estimated Aggregate Private Royalty Income, United States: 2003 – 2012

While these back-of-the-envelope estimates provide useful information, they also highlight the importance of knowing actual private royalty rates. Casual observation suggests that royalty rates have been bid up over time, but many old leases continue to be productive, presumably with lower royalty rates. On the other hand, the recent boom in leasing and drilling across the country, triggered in part by the expansion of the resource base to include unconventional resources, means that there are many newer producing leases that may have higher royalty rates. Given these observations, we now turn to the issue of estimating private royalty rates.

Private Royalty Rates

In our efforts to obtain information on royalty rates in private oil and gas leases, we found that in general, states do not report oil and natural gas production or revenue data in a manner that provides any insights into royalty revenues or rates paid to private mineral owners. The sole exception that we found is Montana, which reports severance tax revenues in a way that allows us to estimate average annual private royalty rates for both oil and natural gas in that state in recent years. Specifically, for the years 2008 – 2012, we are able to estimate the average annual royalty rate paid to royalty owners as, e.g., the taxable royalty income from oil divided by the sum of that income and the working interest income from oil. The average annual estimated royalty rate for oil ranges from 13.3 to 13.8 percent, with an average for the six years of 13.5 percent. The analogous exercise for gas royalties reveals a range from 10.5 to 12.7 percent, with

a mean of 11.8 percent. Montana is unusual in that state mineral leases are issued with different royalty rates for the two products, and our estimates indicate that difference carries over into the private market, at least on average. A similar calculation for royalties received from state minerals suggests these rates are comparable to our estimates of private royalty rates. The average estimated state royalty rate is 12.3 percent for oil and 13.5 percent for gas.[11]

Oil and natural gas resource endowments vary across states, meaning that it may be better to own private mineral rights in some states than others. The partition of mineral ownership between private, federal, and state owners also varies. While comparisons of, e.g., production and revenue shares among ownership types across producing states are potentially confounded, they are also interesting to producers, policymakers, and royalty owners. Table 4 presents comparisons of gross revenues and revenue shares between ownership types for producing states. These comparisons are based on published federal numbers and our estimated values of state and private oil and gas production and revenues. Average gross revenues by resource and ownership types are reported in millions of nominal dollars over the years 2006 – 2010. Two important oil and natural gas producing states—Pennsylvania and West Virginia—are excluded due to missing data on state-owned mineral production.

Table 4: Average Annual Gross Revenues by Resource and Ownership Type, by State

	Average Annual Gross Revenues, 2006-2010 ($ million nom.)						Revenue Shares by Owner		
State	*Private Oil*	*Private Gas*	*Federal Oil*	*Federal Gas*	*State Oil*	*State Gas*	*Private Share*	*Federal Share*	*State Share*
Texas	27,077	36,845	20	151	2,015	2,235	0.935	0.002	0.062
California	10,430	1,457	1,021	25	3,126	323	0.726	0.064	0.211
Oklahoma	3,734	8,355	11	90	1,019	1,832	0.804	0.007	0.190
Louisiana	3,503	7,549	26	181	1,849	1,549	0.754	0.014	0.232
Wyoming	1,478	2,772	1,682	7,321	202	737	0.299	0.634	0.066
N. Mexico	1,403	2,555	1,667	4,823	1,299	1,307	0.303	0.497	0.200

[11] The standard errors of these estimates are sufficiently large that the average state royalty rates for oil and gas are not statistically different from one another. The private rates are statistically different from one another, with a t-statistic of 4.32.

N. Dakota	2,979	228	514	55	1,100	67	0.649	0.115	0.236
Colorado	1,610	5,477	284	1,341	88	63	0.800	0.183	0.017
Kansas	2,073	1,477	24	41	571	329	0.786	0.014	0.199
Utah	887	597	491	1,282	9	36	0.449	0.537	0.014
Arkansas	320	2208	0	68	81	385	0.826	0.022	0.152
Montana	1,721	359	229	153	121	37	0.794	0.146	0.060
Mississippi	1,243	404	18	6	319	69	0.800	0.011	0.188
Ohio	282	467	2	5	72	80	0.826	0.007	0.167
Michigan	359	252	2	25	76	130	0.724	0.032	0.244

Note: Missing data for Pennsylvania and West Virginia preclude their inclusion. Both are predominantly private mineral states.

States are listed in the table in order of average total gross revenues across oil and gas and all mineral ownership types. It is noteworthy that states have very different shares of land in the three ownership categories. Eastern and southern states have more private land as a percentage of total area than do western states. Important producers such as Texas and Oklahoma reflect this fact with large shares of revenue derived from private minerals. Some western states, such as Wyoming, Utah, and New Mexico, derive large revenue shares from production on federal minerals. Large state shares appear in selected states with aggressive state leasing programs, as well as in states with high proportions of state-owned lands.

Once again, private oil and gas royalty incomes are the focus of our interest. We report our state-level estimates of these incomes in table 5. States are ranked by the sum of estimated private oil and gas revenue in 2010, and the reported figures are for that year. Note that this results in a somewhat different rank ordering than in table 4, which was based on total production from all mineral types. We provide two estimates of total private oil and gas royalty income for each state. The first is shown in the fifth column and is calculated using a conservative one-eighth share of total revenue, based on the anecdotal base royalty rate. The second uses the estimated royalty rates derived from Montana—an average rate of 13.5 percent for oil and 11.8 percent for gas.

Table 5: Estimated 2010 Private Oil and Gas Production Revenues and Royalty Income, by State

State	Private Oil Revenue	Private Gas Revenue	Revenues Oil and Gas	Royalty Income using 1/8th Royalty Rate	Royalty Income (Montana Royalty Rates)	Income Share (%) of Total State Income
Texas	30,294	30,179	60,473	7,559.1	7,650.8	0.79
California	10,756	1,120	11,875	1,484.4	1,584.2	0.10
Louisiana	3,411	8,330	11,742	1,467.7	1,443.5	0.86
Oklahoma	3,990	7,000	10,990	1,373.8	1,364.7	1.03
Colorado	2,016	5,089	7,105	888.1	872.6	0.41
N. Dakota	4,583	173	4,756	594.5	639.1	2.15
Wyoming	1,588	2,295	3,882	485.3	485.1	1.90
Kansas	2,286	1,101	3,388	423.5	438.6	0.39
Arkansas	325	2,975	3,300	412.5	395.0	0.43
N. Mexico	1,355	1,864	3,219	402.3	402.8	0.59
Mississippi	1,452	259	1,711	213.9	226.6	0.24
Utah	1,039	645	1,683	210.4	216.3	0.24
Montana	1,452	206	1,658	207.2	220.3	0.63
Michigan	435	309	744	93.0	95.2	0.28
Ohio	277	307	584	73.0	73.6	1.77
All States	67,827	69,068	136,895	17,112	17,307	0.14

Note: Units are millions of nominal dollars.

One way to put the importance of the private royalty income in context is to compare it to all personal income in each state. In the final column of table 5, we report our estimates of private royalty income as a share of state personal income (as reported by the Bureau of Economic Analysis). We estimate these shares using private royalty income estimates that are the simple averages of the private royalty income calculations in the previous two columns. As can be seen, in four states (North Dakota, Oklahoma, Ohio, and Wyoming) private royalty incomes comprise more than 1 percent of state personal income. This comparison relies on two tacit assumptions: one is that all private royalty income is received as part of personal income, which precludes corporate ownership of private minerals. The second is that royalties from production in a state are paid to people who reside in that state. While neither of these assumptions holds without exception, we believe our estimated shares of state personal income offer useful measures of both the magnitude and relative significance of private oil and gas

royalty income on a state-by-state basis. For example, the $1.4 billion in private royalty income generated in Oklahoma is about 10 times more important to that state than the $1.5 billion generated in California.

IV. Discussion

Dramatic changes in the U.S. and North American energy landscape in recent years have stimulated considerable interest, and several attempts have been made to quantify the economic impacts of these changes. The estimates presented here are quite different (both in their magnitudes and in their interpretation) than those in two other recent studies, and it is useful to discuss the differences between our intent and approach and those of two recent reports.

Weber et al. (2013) use USDA ARMS survey data to estimate total payments from natural gas producers and wind energy companies to farm operators as $2.3 billion in 2011. The payments include lease bonus payments as well as net royalties, but do not include royalty payments from oil production. The sample on which their study is based is also limited by the number of recipients that the authors consider. Although agricultural operations account for a large number of acres in important oil and natural gas producing regions, not every agricultural operator receives payment for energy operations. Severed mineral ownership is one important reason for this—northern Great Plains states such as Montana, North Dakota, and Wyoming include millions of acres on which private surface owners engage in agriculture on lands that lie above federally-owned minerals.[12] A second reason is that many agricultural producers themselves operate on leaseholds; energy royalty payments are unlikely to flow to the lessee

[12] These states have 27.8 million acres of private surface rights with severed minerals held by the federal government (Public Land Statistics).

under such an arrangement. These institutional factors make their estimates incomplete and potentially biased downwards.

A second recent contrasting study is an aggregate economic impact analysis that estimates the total contribution to GDP of unconventional oil and gas resources at $284 billion in 2012 (IHS 2013). While private royalties from oil and gas production are embedded in this figure, so also is the aggregate investment in upstream infrastructure ($238 billion), which includes lease bonus payments. This figure is commensurate with our estimate of total revenue from both conventional and unconventional oil and gas production in 2012. The IHS study also tries to isolate the effect of unconventional deposits from the large aggregate impacts of conventional deposits; a multiplier effect of the unconventional investments is embedded in the estimate. Although the estimates obtained in both of these recent studies differ from ours by (roughly) a factor of ten (one higher, one lower), neither study is designed to answer the question that we address.

Private royalty income represents a particular pathway for wealth creation, and we believe that our estimates of this income provide valuable insights and information. There is a long list of additional questions related to royalty income that we do not address here. For example, knowledge of the distribution of payments to private royalty owners would be interesting. The $22 billion in estimated annual royalty payments is likely to have different effects if each U.S. resident receives $70 per year than if 20,000 royalty owners receive more than $1 million each year. Understanding such effects becomes more important as time passes because fractionation of mineral interests is increasing as the interests are passed down through families. To the extent that this is a greater issue in locations with a longer production history, the effects could well be disparate across the country. They may also differ between oil royalties

and those for natural gas, because natural gas has often been considered a less valuable byproduct of oil production.

Our estimates of state-level private royalty income are based on the assumption that royalty payments from production in a particular state go to residents of that state. The greater the level of fractionation in a state, the further from reality is our assumption on this point. Our estimates of gross royalty income do not account for two important subtleties of royalty payments. First, we do not attempt to estimate net royalties received. Gross royalty payments to private mineral interests are often reduced by a variety of deductions and transportation allowances before the production company cuts the check to the landowner.[13] Accounting for deductions and allowances is important for royalty owners, in particular the auditing of claimed marketing expenses. Gross royalty amounts are also commonly reduced by severance taxes imposed in most states. The remaining royalty income received by private mineral owners is subject to state and federal income taxes. Failing to account for such factors will result in estimates that overstate the economic impacts of private oil and gas royalties to mineral owners. Further refinements to our estimates would benefit greatly from an accurate accounting of the deductions, allowances, and taxes that comprise the difference between gross and net royalty payments. Such an accounting would require access to data not available to us for our inquiries.

Deductions are related to a critical issue that affects all royalty recipients, regardless of ownership type: dispersion in price received per unit of oil or natural gas extracted. By using state-level average prices, we assume that all royalty owners receive the same price for their products. This may or may not be the case. If, for example, federal minerals are systematically

[13] A recent dispute between royalty owners and Chesapeake Energy in Pennsylvania centers around deductions from royalty checks far in excess of historic levels, and even in excess of deductions made by Chesapeake's partners on the same leases. See Scheyder (2013).

located further from sales locations, then we might expect the sale price from federal leases to be different than from state and private leases. More systematic collection and analysis of data on lease and sales provisions would be required to determine whether or not this is a real concern, and whether significant bias is introduced by ignoring it. In addition to spatial basis differentials, there could be temporal differences. Differences in sale price could then be magnified or offset by deductions or taxes.

The historical standard for royalty calculation has been wellhead value. Because products are not always sold at the wellhead, agreeing on the spatial and temporal price at the wellhead is nontrivial and potentially contentious. Private royalty owners have limited ability to audit reported quantities or sale prices, which has led to disputes between operators and royalty owners.[14] One potential solution to price verification and royalty deductions is the adoption of indexed royalties. Instead of calculating or imputing a wellhead price, a benchmark or index price could be agreed upon in advance, perhaps with a basis correction. The royalty rate remains negotiable, and we might expect more remote mineral owners to accept a lower royalty rate or a different benchmark index. The advantage is that the royalty calculation is more transparent.

While royalty owners are always focused on check stub issues such as price calculation, they also have a considerable stake in broader policy issues such as natural gas exports, royalty incentive programs, and severance tax reductions.

V. Conclusion

In this study, we use data from various sources to calculate production from private minerals as the difference between total production and the sum of production from federal and

[14] A recent example is *Shell v. Ross*, which was eventually decided by the Texas Supreme Court in December 2011.

state minerals. We then approximate the gross value of private production by using reported annual state-level wellhead prices for natural gas and first transaction prices for oil. This gross production value is generally the basis for payments to private royalty owners. Finally, we estimate private royalty income using the (limited) information available on royalty rates in private oil and natural gas leases.

Our estimates suggest that oil and gas royalty payments to private mineral owners are substantial. Acknowledging that gross production value fluctuates with prices, we estimate that in 2012, $22 billion was owed to private owners of onshore oil and gas minerals. Texas is far and away the state with the greatest private oil and gas royalty income, with estimated payments of roughly $7.5 billion in 2010. In addition, California, Oklahoma, and Louisiana are all estimated to generate over $1 billion dollars in private royalty income each year.

Our aggregate royalty income estimate is likely to be an upper bound on the net gains to private mineral owners because it does not account for adjustments typically made by producers for various deductions and allowances before checks are cut to royalty owners. Our estimates are also high insofar as some producers do not make royalty payments because they own the mineral interests to land on which they are operating. A final point is that the available data only allow us to trace royalty income to its state of origin, as opposed to the state in which the recipients reside. This feature of our data does not impart bias on our aggregate estimates of royalty income, but it may affect the distribution of the benefits of that source of income across states. Determining exactly how the interstate distribution of income is affected by this feature would require far more detailed data than are currently available to us.

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