U.S. Private and Natural Gas Royalties: Estimates and Policy Consideration

by

Timothy Fitzgerald

and

Randal R. Rucker*

March 12, 2014

* Assistant Professor and Professor, Department of Agricultural Economics and Economics, Montana State University. Send correspondence to timothy.fitzgerald@montana.edu. We thank Chris Watson for assiduous research assistance and the ROPE Coalition for encouragement and financial support. Any errors are our responsibility.

1. Introduction

The United States is the only country in the world with widespread private ownership of minerals. This private ownership has made many U.S. 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, the ownership of oil and natural gas resources has reemerged as an important factor in determining the course of the energy industry. Private oil and gas ownership is acknowledged to be an important contributor to innovations in the development of unconventional resources and the technologies used to produce them (Yergin 2011). Little is known, however, about the aggregate value of private mineral interests or the annual income derived from them. Private minerals typically are extracted under the provisions of leases with developers that specify the royalty rate to be paid on the gross revenues from the production of oil and natural gas. In this paper we estimate private oil and natural gas royalty gross incomes in recent years, for the continental United States and the individual states therein.

Our estimates indicate that in 2012 an estimated 77 percent of oil and natural gas revenue from onshore sources in the lower 48 states was from private minerals.[1] These are substantial pieces of an extremely large pie. We estimate that in 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. Gross Domestic Product (GDP).

The corresponding value of production from private minerals was about $161 billion in 2012, of which private royalty owners were paid $22 billion in gross compensation for their

[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.

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. If private royalties are expressed 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.

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] 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 approach we adopt to estimate revenues from privately owned oil and natural gas production 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

[2] In 2013 the United States became the world's leading producer of natural gas, and it remains the third-largest producer of crude oil, after Saudi Arabia and Russia (International Energy Agency 2013).

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 our approach 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 employ two methods for estimating the share of gross revenues received by royalty owners. The first of these methods is based on anecdotal information regarding royalty rates, while the second is based on average royalty rates in private leases located in Montana, which to our knowledge is the only state that reports such information. We then discuss four categories of policy issues for which our royalty estimates have relevance—trade restrictions and opportunities, refinery and pipeline capacity constraints, tax policies, and regulation of technology.

In section 2 below, we present background information that provides context for the estimates that follow. We develop and present our estimates of production, value, and royalty income for private minerals in the third section. In the fourth section, we discuss our results. We discuss policy issues in the fifth section and provide concluding thoughts in the sixth section.

2. Materials and Methods

2.1 Aggregate Production

Thanks largely to a confluence of technological advances, in recent years both oil and natural gas production have increased in the United States. 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 technologies themselves have been known for some time (Bohi, 1998), but the improving 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, although relatively small amounts of natural gas are traded via pipeline 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.

Oil and natural gas production is determined in part by the inventory of wells, which in turn depends on two primary factors. The first is the number of new wells drilled; the second is the number of old wells that are brought back into production during periods of high prices. The second column in table 1 reports the total number of producing oil and natural gas wells over the past decade. The change in the producing well inventory is the number of new wells drilled plus old wells brought back into production, less the number of older wells that reach the end of their useful life. The third column in table 1 reports the number of new oil and gas wells drilled each year during the past decade. Relatively high prices are expected to trigger higher production as more new wells are drilled and older wells are brought back into production.

Table 1 also provides information on oil and natural gas production and prices over the decade from 2003 to 2012. 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.

Nominal 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 in 2003 to less than $3 per unit in 2012.[3] The table also reports real prices, using the producers' price index less food and energy with 2007 as a base year.[4] These aggregate annual averages mask price dispersion from a broad range of sources including differences in grades of crude, as well as in spatial and temporal basis for both oil and gas. 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.

[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. See, e.g., Ramberg and Parsons (2012).
[4] Because real and nominal values do not vary dramatically over the short time span of our analysis, below we focus primarily on the nominal values.

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 both oil and gas. 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.[5] Unfortunately, the fragmentation of markets for these products makes analysis difficult, so we exclude them from the discussion below.

Oil revenues were more than five times higher in 2012 than in 2003, but natural gas revenues were about 17 percent lower, as can be seen in table 2. Because domestically produced natural gas has very limited 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.

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. GDP in 2012.

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

This percentage might seem small, but these revenues were greater than the GDP of 30 individual states in 2012.

2.1.1 Oil and Gas Leasing

In the United States, mineral rights are owned by the federal government, individual states, sovereign tribal governments, and private landowners.[6] The division among these four groups varies substantially between states. While the federal government owns the minerals for 39.8 percent of the total land area in the lower 48 states, this share varies widely from state to state. Similarly, the share of minerals owned by state government varies across 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

[6]Definitive data on production from tribally-controlled minerals are 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 a host of 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 vary both within and between states. 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.[7] Companies, who must pay the costs associated with the development,

[7] 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.

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.[8]

2.2 Production from Federal Minerals

Federal mineral production is an important policy topic in its own right (Boskin et al., 1985). The top panel of figure 1 shows the production amounts 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.

A longer series is available for oil production from onshore federal minerals. This series is shown in the bottom panel of 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

[8] 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. Data on these leases and royalties are available from the Office of Natural Resource Revenue.

in gas production. The long-term decline in oil production is pronounced, though recent years have seen production stabilize and even inch upwards.

2.3. 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 (BLM 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 3. In addition to indicating the states and years for which data are available, the average annual 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.

Focusing on the past decade, only five states have largely complete state mineral production reports—Louisiana, Michigan, Montana, New Mexico, and Texas. For the other four states with partial records, we estimate values for missing years by attributing a state-specific constant proportion of production (calculated from available data) 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.[9]

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

To estimate production shares from state-owned lands for these eight states, we use the 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 states, we use an average of the other six states in table 2 to construct an estimate of state mineral production.[10]

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 production from state minerals is North Dakota, which has experienced a dramatic increase in oil production from all mineral ownership types thanks to development of the Bakken shale formation. The reported increase in aggregate 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.

In aggregate, natural gas production from state-owned lands has fallen over the past decade. Since 2008, states managing mineral resources to fund public schools might have been 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.

2.4 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

[10] 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).

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 the increases mentioned above in state production in North Dakota and Texas, it is 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 also 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. Considering the importance of privately-owned Eastern shale resources for natural gas, but not oil production, this is not surprising.

3. Results

3.1 Private Mineral Gross Production Revenue and Royalty Income

3.1.1 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 state-level average annual price to each unit of oil 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.[11]

Table 4 reports our estimates of aggregate gross revenue from private production for all states over the period 2003 – 2012. Oil and gas revenues (in billions of dollars) are reported separately, and in total, both in nominal and real terms.

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 4 provide the basis for an estimate of gross private royalty income. Figure 3 shows annual (nominal) 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 3, 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.

[11] 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 and the reported U.S. prices to predict annual state-level wellhead prices for 2011 and 2012.

While these back-of-the-envelope estimates provide useful information, they also highlight the importance of knowing actual private royalty rates. Anecdotal evidence suggests that royalty rates have increased over time, but many old leases continue to be productive, presumably with relatively low 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.

3.2 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 Montana royalty owners as 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 five 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 oil and natural gas, and our estimates indicate that difference carries over into the private market, at least on average. The average estimated state royalty rate is 13.2 percent for oil and 14.8 percent for gas.[12]

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 based on our analysis of, for example, production and revenue shares among ownership types across producing states are admittedly crude, they are also of considerable potential interest to producers, policymakers, and royalty owners. Table 5 presents comparisons of oil and natural gas gross revenues and revenue shares for producing states for each of the three ownership types (federal, private, state). 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.

States are listed in table 5 in order of average total gross revenues for oil and natural gas summed across all three 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

[12] 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.

western states, such as Wyoming, Utah, and New Mexico, derive large revenue shares from production of federal minerals.

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 6. 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 5, which was ordered based on average total revenues from all three mineral ownership types over the years 2006-2010. 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 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.

The figures in table 6 are specific to 2010. The gross revenue from oil and natural gas production of private minerals comprised 76 percent of aggregate revenues across all mineral ownership types.[13] We estimate that total private royalty income in 2010 was just over $17 billion. A similar calculation of private royalty income for other years can be derived from the combined nominal production revenue figures in table 2. The increasing total revenues from oil and natural gas production on private minerals, which are largely the result of higher oil production and prices, yield estimates of $22 billion in private royalty income in 2011 and $21 billion in 2012.

[13] This percentage is calculated as the ratio of the "All States" value in the fourth column of table 6 to the 2010 value in the final column of table 2.

One way to place the importance of the private royalty income in context is to compare it to total 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, the first being that all private royalty income is received as part of personal income, which precludes corporate ownership of private minerals. The second assumption is that royalties from production in a state are paid to people who reside in that state. While there are exceptions to both of these assumptions, 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 represents about a ten times larger share of income than does the $1.5 billion generated in California.

4. 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 various dimensions of the economic impacts of these changes. Our estimates are different both in their magnitudes and in their interpretation than estimates developed in two other recent studies. It is useful to discuss the differences between our intent and approach and theirs.

Weber et al. (2013) use USDA Agricultural Resources Management Survey (ARMS) 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. Their sample includes a few hundred farms that receive payments and their estimates of cumulative payments are obtained by extrapolating from the survey responses. There are at least three reasons to think that the estimates developed by Weber et al. may substantially underestimate income from the development of private energy resources. First, many agricultural producers operate on leaseholds, and energy royalty payments are unlikely to flow to the lessee under such arrangements. Second, severance of private minerals may prevent a surface owner such as an agricultural operator or lessee from receiving royalty revenue. Third, royalty payments from oil producers to private mineral interests are substantial and are not included in the estimates developed by Weber et al.

A second recent contrasting study is an aggregate economic impact analysis that estimates the total contribution to GDP of unconventional oil and gas resources to be $284 billion in 2012 (IHS 2013). While private royalties from oil and gas production are a component of this figure, so also is the aggregate investment in upstream infrastructure ($238 billion), which includes lease bonus payments as well as capital expenditures on wells, pipelines, and related equipment. The IHS study tries to isolate the effect of unconventional deposits from the large aggregate impacts of conventional deposits. Moreover, 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 allow us to expand our analysis. The $22 billion in estimated 2011 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 implications of fractionation could well be disparate across the country.

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. Further, an estimate of gross royalty income does 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.[14] 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, and the remaining royalty income received by private

[14] These deductions can be a source of acrimony between private mineral owners and producers. For example, 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).

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 abstract from the fact that all royalty owners may not receive the same price for their products. If, for example, federal minerals are systematically located further from sales locations, then we might expect the sale price from federal leases to be less than from state and private leases. The prices we use are weighted averages of sales across all ownership types. If prices received for sales from private minerals are higher than the average across all ownerships, then we are underestimating revenue from private minerals. More systematic collection and analysis of data on lease and sales provisions would be required to determine whether or not price dispersion is a real concern, and whether significant bias is introduced by ignoring it. In addition to spatial basis differentials, there may also be temporal differences.

The historical standard for royalty calculation has been wellhead value. Because products are not always sold at the wellhead, however, agreeing on the spatial and temporal price at the wellhead is nontrivial and potentially contentious. Private royalty owners have limited ability to audit or otherwise authenticate the quantities and sale prices claimed by operators as the basis for determining royalty payments. This has led to disputes between operators and royalty owners.[15] One potential solution to problems associated with price verification and disputed 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 basis corrections that vary across mineral owners. Alternatively, because the royalty rate remains negotiable, we might expect more remote mineral owners to accept lower royalty rates. Different benchmark indexes might also be used between different operators and mineral owners. The advantage of such arrangements is that the calculation of the net royalty payment is more transparent. A possible disadvantage is that up-front lease negotiation costs may be greater.

While royalty owners are always focused on check stub issues such as price calculation, they also have a considerable stake in broader policy issues. We turn now to some of the policy questions for which our estimates have relevance.

5. Policy Issues and Implications

Gross royalty revenues are affected by three factors—product prices, production quantities, and royalty rates. Because the royalty rate for any given lease is fixed for the life of the lease, we focus on price and production effects related to four policy issues: trade restrictions and opportunities, refinery and pipeline capacity constraints, tax policies, and regulation of technology.

[15] A recent example is *Shell v. Ross*, which was decided by the Texas Supreme Court in December 2011. The primary issue in this case was the calculation of royalties. The royalty owner was awarded compensation.

5.1 LNG and Oil Exports

5.1.1 LNG Exports

The trade issues relevant for domestically-produced natural gas are fundamentally different than those for petroleum. The majority of natural gas consumed in the United States is from domestic sources; EIA data indicate that net imports peaked in 2007 at 20 percent of U.S. consumption and have been falling since. Canada is by far the most important trading partner, accounting for 60 percent of exports and 90 percent of imports. This trade is carried almost exclusively by pipelines, as is a smaller volume of trade with Mexico. Shipments of natural gas to and from other trading partners require liquefaction of natural gas for ocean transport. Liquefaction capacity in the United States is currently extremely limited, and almost all existing capacity is designed to accommodate imports of liquefied natural gas (LNG).[16]

A recently as 2011, analyses of the limited U.S. capacity for handling liquefied natural gas focused on imports (Maxwell and Zhu 2011). Increased U.S. natural gas production, however, has resulted in reductions in the domestic price of natural gas while prices have remained high in Europe and Japan. Figure 4 illustrates that prices in the three markets moved together until the middle of 2008, when U.S. prices declined dramatically. Domestic natural gas prices have not since returned to their earlier highs, and it appears that there are arbitrage gains from exporting gas from the United States to European and East Asian markets.

[16] According to the U.S. Office of Oil and Gas Security and Supply, in 2013 the United States imported a total of 96.3 Bcf of LNG, which amounts to about 0.38 percent of total consumption. These shipments were received at five locations and originated in five countries. There were no exports of domestically-produced LNG from the United States in 2013, but 2.7 Bcf were re-exported to Mexico. http://energy.gov/fe/downloads/lng-monthly-report-december-2013

As a result of these changes, expansion plans in the United States are now focused on increasing LNG export capacity. As of December 2013, total approvals for export capacity amounted to nearly 14 trillion cubic feet per year, which is more than half of U.S. consumption in recent years and is approximately equal to the current world LNG production capacity. [17] Thus, even as the prospect of trade promises higher prices for U.S. producers, it is important to recognize that non-marginal changes in trade volumes are likely to have price effects in global markets.[18] Moreover, fixed investments in liquefaction facilities are substantial, so the ability to write long-term contracts is a key consideration for prospective exporters.[19] At present, signed contracts for the delivery of U.S.-produced LNG to foreign markets only account for about 2 percent of U.S. natural gas production (Vucmanovic and McAllister 2014).

The price relationships discussed above suggest that policies designed to accommodate LNG exports are expected to benefit private royalty owners, although the magnitude of such benefits is difficult to predict. As can be seen in figure 4, the gaps between U.S. prices and potential export markets prices in Europe and Japan were roughly \$8 and \$13 per MMBtu in 2012. Even after accounting for liquefaction, transportation and regasification costs, these price differences appear to offer the opportunity for a substantial price increase for domestic natural gas producers.[20] Given that private mineral owners are paid a percentage of production revenues, a portion of the gains from price increases could be passed along to them. How large

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[17] See http://energy.gov/sites/prod/files/2013/12/f5/Summary%20of%20LNG%20Export%20Applications_0.pdf for a listing of the applications to export domestically produced LNG that have been received by the Department of Energy.

[18] We make no attempt here to conduct a thorough study of LNG markets. See Sarica and Tyner (2013) and Medlock (2012), for two of the numerous studies that discuss future prospects for world natural gas markets.

[19] The Office of Fossil Energy (2005) estimates the cost of liquefaction and regasification facilities capable of handling 350 Bcf per year at \$1.9 to \$2.4 billion. This represents between 1 and 2 percent of annual U.S. consumption.

[20] Liquefaction, transportation, and regasification costs typically range from \$4 to \$7 per MMBtu. See *The Economist*, 2012.

such gains may be will be determined by royalty rates, the magnitude of the price increase, and the quantity of natural gas produced from private mineral rights.

Regarding the magnitude of price increases, in the long run, entry into the LNG market will continue until inter-market differences in prices equal the costs of liquefaction, transport, and regasification. This entry process is presently underway. In addition to the applications to expand U.S. LNG export capacity referenced above, construction of liquefaction plants is underway in a number of other countries.[21] If United States natural gas enters world export markets, economic trade models suggest that U.S. natural gas prices will increase and world prices will fall. The magnitude of these price changes and the resulting impacts on private royalty income will depend on a number of demand and supply elasticities, as well as on expectations about future market conditions.[22] While we make no attempt here to predict the increase in U.S. prices, our estimates of private royalty income do provide the following insights into the potential gains to private owners of mineral right.

Our estimate in table 4 of revenues from the production of natural gas associated with private mineral rights is $51.38 billion for 2012. At the average Montana royalty rate of 11.8 percent, private royalty income was $6.06 billion. From table 1, the average price of natural gas

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[21] Currently Qatar is the largest exporter of LNG, accounting for roughly 25 percent of world exports (The Economist, 2012). Countries in which plants with notable capacity are under construction include Algeria, Angola, Indonesia, Malaysia, and Papua New Guinea. The country in which the most capacity is under construction is Australia, which is predicted to be on a path to overtake Qatar as the largest LNG exporter within a few years. See Appendix II in "World LNG Report," 2013.

[22] Both short- and long-run elasticities will be relevant. Even if long-run elasticities are such that the increase in U.S. natural gas prices is relatively small, private mineral rights owners stand to gain substantially from short-run increases in price. Suppose, for example, as a result of entering world LNG export markets, U.S. prices increased by 25 percent of the recent difference in the U.S. and Japanese prices for only two years. The figures discussed in the next paragraph in the text suggest that private royalty income would increase by more than $10 billion. Regarding the importance of future expectation about future market conditions, recent indications are that agreed-upon prices in the signed contracts for long-term arrangements to purchase U.S. LNG are lower than might be expected given current world and U.S. prices (Vucmanovic and McAllister 2014).

in 2012 was $2.66 per Mcf, implying that private production was about 19,316 bcf (= $51.38 billion/($2.66/mcf)). At that production level, each $1 per Mcf increase in natural gas prices will increase gross private natural gas revenues by $19.316 billion and—at a royalty rate of 11.8 percent—will increase private royalty income by about $2.28 billion.

5.1.2 Crude Oil Exports

Next consider issues associated with trade in crude oil. As with natural gas, U.S. oil prices have historically moved closely with world crude prices, but U.S. prices have recently fallen below world prices.[23] From early 2011 until early 2013, the (U.S.) WTI price was less than the simple mean of the Brent and Dubai prices by an average of about $15 per barrel (World Bank Pink Sheet). Whereas limited LNG liquefaction facilities constrain international trade in natural gas, international markets for trade in crude oil are well-established, facilitated by the low cost of shipment relative to value.[24] U.S. crude oil producers cannot, however, benefit from recent world and domestic price differences because—since the Energy Policy and Conservation Act of 1975 was enacted—the United States has banned exports of crude oil.[25] Without access to export markets, recent increases in U.S. crude oil production have resulted in falling domestic prices and the differences noted above between U.S. and world crude oil prices.

If crude oil export bans were lifted, domestic crude would likely sell for the higher prices being paid in world markets. This would benefit domestic oil producers, and would also result in

[23] Buyunkuski et al. (2013) suggest that this divergence is unusual.
[24] EIA data indicate that the average transportation cost (estimated as the difference between landed price and FOB price) of crude oil imported from all sources is less than 1 percent of the value of oil. This is much lower than transportation costs for LNG.
[25] Public Law 94-163. There are exceptions to this ban, including crude oil exports to eastern Canada; Canada, however, remains a net importer of crude to the United States. Some crude from Alaska was historically exported directly to customers in East Asia, but those exports have stopped with depleted production in Alaska.

increased private royalty payments. As with natural gas, although it is difficult to predict the magnitude of the domestic price increase, our estimates of private royalty income provide insights into the possible gains to owners of private mineral rights from lifting export bans on crude.

Our estimate in table 4 of revenues from the production of crude oil from private mineral rights is $123 billion in 2012. At the average Montana royalty rate of 13.5 percent, private royalty income was $16.6 billion. From table 1, the average price of oil in 2012 was $94.11 per barrel, implying that private production was about 1.307 billion barrels. At that production level, each $1 per barrel increase in crude oil prices will increase gross private natural gas revenues by about $1.307 billion and—with a royalty rate of 13.5 percent—will increase private royalty income by about $176 million.[26]

The political economy of oil trade issues is complicated. Oil producers and royalty owners would both benefit from the higher domestic crude prices that would result from lifting bans on exports. Refiners would likely pay higher crude prices and would likely pass along some of those costs to domestic consumers in the form of higher gasoline and diesel prices. For those refiners that also produce crude oil, the decision about whether to lobby for the lifting of crude export bans involves an internal calculus about which we have little insight. We do, however, observe that one such firm—Exxon—has recently endorsed lifting the crude oil export ban (Gilbert 2013).

[26] The potential gains from a $1 increase in natural gas prices are greater than the gains from the same change in the price of oil. Alternatively, based on 2012 prices, the gains to private royalty owners from a 10 percent increase in natural gas prices would be about $570 million, whereas for oil the gains would be almost $1.7 billion.

An additional consideration is that whereas export of domestic crude oil is currently banned, there are no restrictions on the export of refined products. As a result, domestic refiners have benefitted recently from low domestic oil prices and are able to sell their output (gasoline and diesel) into world markets where they compete against foreign refiners paying the higher world prices for crude oil. Although the U.S. share of the world diesel market is substantial, the share of the world gasoline market is quite small. Insofar as gasoline export prices are determined in world markets and are effectively exogenous from the perspective of U.S. refiners, any increase in crude prices may simply result in a transfer of rents from refiners to crude oil producers and (through royalty payments) private mineral interests. Thus, although the interests of oil producers and private royalty owners align on the issue of allowing oil exports, independent refiners (and possibly some integrated refiners) will resist eliminating the export ban.

5.2 Midstream Capacity

There are at least two issues related to refinery and pipeline capacity that have potentially important implications for private royalty incomes.

5.2.1 Refining Capacity

The refinery capacity issue stems from the fact that much of the crude oil coming from unconventional domestic sources is light sweet crude. Collectively, domestic refiners have limited capability to refine this crude because a substantial fraction of their capacity is configured to refine heavy imported crudes. Refiners are able to accommodate different crude grades, albeit it at cost, and if relative prices are low enough, they may be willing to operate refineries suboptimally. Brown et al. (2014) estimate recent discounts on crude oil in the Upper Midwest (PADD 2) to be $14.83, and they attribute this discount to mismatched refining capacity and crude oil production. This discount suggests that the refineries in the Upper Midwest and Gulf Coast regions that are configured to process light sweet grades of crude are at their capacities. The discount also provides an indication of the costs (at the margin) to refiners of switching from processing the heavy crudes they are configured to handle to the light sweet crudes now being produced in the Northern Plains.

Brown et al. also determine that allowing the export of domestic crude would have only a very small downward impact on world prices (about $0.01 per barrel). As a result, crude prices in the Upper Midwest would increase by virtually the full amount of the $14.83 price discount. It follows that crude oil producers and royalty owners (in particular, those in the Northern Plains) could benefit substantially from allowing exports.[27] Balistreri et al. (2010) estimate elasticities between disaggregated crude oil streams and find substantial substitutability between crude streams in the long run. This suggests that whereas the refining capacity constraints may be effectively binding in the short term, they are likely to become less important over time as refineries are reconfigured.[28]

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[27] A crude estimate of the benefits to royalty owners in the Northern Plains from allowing exports is obtained as follows. Recent estimates reported in the media suggest that about one million barrels of oil are being produced daily in the Bakken play (Gold and Friedman 2013). A $14.80 increase in oil prices would increase the daily value of the Bakken oil by $14.8 million. The figures presented in table 5 suggest that about 65 percent of the oil in North Dakota comes from privately owned oil rights. Assuming that this percentage holds for the Bakken, the daily value of the private oil produced would increase by about $9.6 million. Using the Montana royalty rate for oil of 13.5 percent, royalty owner income would increase by about $1.3 million per day or about $474 million annually as a result of allowing oil exports. The crude oil being produced from the Eagle Ford formation in Texas is also light sweet (Brown et al. 2014). Assuming that production from this source is about 1.3 million barrels per day (Gold and Friedman 2013), calculations analogous to those above for North Dakota suggest that allowing exports would increase Texas royalty owner income by about $2.4 million per day or $880 million annually.

[28] We are not aware of any research that would allow us to directly estimate the current short run price elasticity of refinery demand for light sweet crude.

5.2.2 Transportation Capacity

Oil extracted from unconventional formations in the continental United States can be transported through pipelines either to Midwestern or Gulf Coast refineries. With the recent increases in domestic production, however, pipeline constraints for transporting crude from the northern Great Plains to the Gulf Coast have become binding. Borenstein and Kellogg (2014) make the argument that as a result, the prices paid for continental crude oil by Midwestern refineries have fallen relative to prices paid by Gulf Coast refineries.[29] They also determine that these low inland prices have benefited Midwestern refineries, in part because they have not seen commensurate reductions in the prices at which they sell their gasoline. On the other hand, royalty owners and their working interest partners in the northern Plains have certainly suffered from the lack of available capacity.[30]

It is noteworthy that the analyses of Brown et al. and Borenstein and Kellogg attribute the same price differential to two different causes—the former study attributes it to limited light sweet refinery capacity, whereas the latter attributes it to binding pipeline capacity constraints. It is also noteworthy that if binding refinery capacity is the cause of the price differential, then eliminating the export ban will cause Midwest crude oil prices to rise, thereby benefiting royalty owners. If on the other hand, the price differential is due to binding pipeline constraints, then

[29] As a result of the price differences, producers have turned to substitute modes of transportation—importantly, rail transport. The highly-publicized rail accidents associated with this switch have distracted the media from the real constraint—a lack of adequate regional pipeline capacity.

[30] Borenstein and Kellogg (B-K) suggest that pipeline constraints have caused the prices received by crude oil producers to fall by $17.45 and that expansion of capacity "will primarily increase the Midwest crude oil price rather than decrease the Gulf Coast price because the Gulf Coast is tied to the very large world market, of which the Midwest is only a small part" (p. 29). Assuming, for convenience, that the increase in capacity will cause Midwest prices to rise by $15, the back of the envelope impacts on royalty owner income are roughly the same as the estimates of the impacts of increased refinery capacity presented in footnote 27 above. B-K also point out that the price difference will not persist in the long-run and mention several pipelines that are under consideration or actually under construction. For additional details on pipeline projects see Gaswami (2012).

lifting the export ban will not cause Midwest crude prices to rise because the pipeline constraint will not be affected by allowing oil exports.

5.3 Tax Policies

A third set of policy issues that directly affect private royalty owners is taxes. Many states have seen budget shortfalls in recent years, and budget directors are looking for additional revenue sources.

5.3.2 Severance Taxes

Most states have severance or production taxes on oil and natural gas. Through these taxes, increased oil and gas production has resulted in increased revenues flowing into state treasuries. Revenue-seeking budget mavens are looking at these flows and thinking that higher tax rates would yield even more revenue.[31] Production from federal minerals is not subject to state taxation, and states do not generally impose severance or production taxes on revenues generated from state-owned minerals.[32] That leaves private royalty owners and their working interest partners to bear the brunt of any prospective severance tax increases. Our royalty income estimates do not account for the tax liabilities that private royalty owners incur. Severance tax regimes vary across states: some are a flat percentage of gross wellhead value, others are progressive schedules, some have rates that vary with oil and gas prices, some have

[31] Pennsylvania recently implemented an impact fee (equivalent to a specific tax) for new wells. In Montana, there has been a suggestion of altering the state's tax system to increase tax revenues from oil and natural gas production (Bozeman Daily Chronicle, 2014).

[32] The federal government refunds a portion of revenues from leasing and production of federal oil and gas back to states and counties in which the lands are located to compensate for uncollected tax revenue. State minerals generate revenues directly for the states in which they are located.

reduced rates for stripper wells, others offer tax holidays for new wells, and so forth.[33] For this reason, combined with the fact that we do not have the information that would be required to determine the relevant marginal tax rate in states with complex systems, our royalty income estimates do not account for the tax liabilities that private royalty owners incur. We can, however, provide some insights into the magnitude of the impacts of increases in severance tax rates for some states.

Consider, for example, three states with relatively straightforward severance tax regimes—Louisiana, Texas and Wyoming. Most state severance tax rates are a percentage of the gross value of the oil and natural gas produced. For example, Texas has tax rates of 7.5 percent on gas and 4.6 percent on oil, whereas Wyoming has tax rates of 6 percent for both oil and natural gas. Louisiana currently has a severance tax rate of 12.5 percent for oil and $0.118 per Mcf of gas.[34] Table 7 displays our estimated impacts on severance tax payments made by royalty owners for each of these states. The hypothetical changes in the tax rates are 25 percent and 50 percent increases.[35] As can be seen, in Wyoming a 25 percent increase in the severance tax rate would increase tax revenues by $7.4 million. In Wyoming, as well as the other states, the percentage reduction in royalty income is exactly equal to the percentage increase in tax

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[33] For example, in Colorado, the marginal severance tax rates for both oil and natural gas vary from 2 to 5 percent depending on the amount of income an individual receives in a given year. In Oklahoma, the severance tax rate varies with the prices of oil and natural gas. In Montana, revenues are taxed at a 0.5 percent rate the first twelve months a well produces, and production from stripper wells is taxed at rates that vary positively with the level of production and that are lower than the rates for non-stripper production. Montana also taxes the working interest partners at a different rate (9.26 percent) than the non-working interest partners (15.06 percent).

[34] The severance tax rate for gas in Louisiana is adjusted annually, but can never be less than $0.07/mcf. Louisiana also has a lower tax rate (3.125 percent) on oil produced from stripper wells. We assume for the purposes of the calculations in table 7 that all oil production is from non-stripper wells.

[35] Although these estimates are informative, they are also admittedly very crude. The calculations assume that prices and quantities produced are at their 2010 levels, and that the increases in tax rates affect neither prices nor quantities. We speculate that oil and natural gas prices may not change by much in response to a severance tax rate increase because any quantity changes in a given state will be small relative to the size of the market. Insofar as supply of crude oil is relatively inelastic, the reduction in quantity produced will be relatively small. We also do not differentiate between the short and long run .

revenues. Estimated royalty incomes in Louisiana and Texas are much larger than in Wyoming, as are the estimated changes in royalty incomes from a 25 percent increase in severance tax rates. In Louisiana, the estimated reduction in royalty rates is almost $70 million and in Texas the reduction is almost $115 million. In all cases, a 50 percent increase in severance tax rates has twice the impact on tax revenues and royalty incomes as a 25 percent increase.

5.3.2 Percentage Depletion

Because oil and gas are nonrenewable resources, the tax code allows a limited number of producers the option to claim depletion as a fixed percentage (currently 15 percent) or gross revenues rather than calculating depletion based on costs. Integrated oil companies and entities producing the equivalent of more than 1,000 barrels of oil per day cannot claim percentage depletion. The percentage depletion allowance is a federal tax provision that has repeatedly been proposed for reform. A 2013 report of the Joint Committee on Taxation (JCT) suggests that repealing percentage depletion would increase federal revenues by $11 billion over 2013-2023. Our estimates allow for a rough approximation of the importance of the allowance to royalty owners. Royalty owners often have low basis in their mineral property, or find it difficult to calculate their cost basis, which requires a detailed calculation of reserves, As a result, royalty owners often claim percentage depletion. Based on recent royalty income of about $20 billion annually, the 15 percent allowance reduces taxable royalty income by about $3 billion per year.[36] Assuming an average tax rate of 33 percent, eliminating the allowance would increase royalty owners' tax liability by nearly $1 billion each year. This suggests that the incidence of

[36] For simplicity, this assumes that all royalty owners take the 15 percent allowance and that no royalty owners hit the 1,000 bpd or 65 percent of total income limits. Our search of the literature suggests there has been virtually no careful analysis of the impacts of this tax provision.

eliminating the percentage depletion allowance as anticipated by JCT (2013) falls almost entirely on royalty owners rather than their working interest partners. It is important to note that our estimate is potentially an overestimate because some royalty owners would be able to claim cost depletion. It also does not anticipate any long-run effects as the leasing markets adjust.

5.4 Upstream Technology

A final policy concern for which our estimates may have relevance is regulatory reform affecting exploration and production technologies. Hydraulic fracturing (fracking) has been a major factor in expanding production of both oil and natural gas. Fracking has also received widespread attention and criticism from environmentalists concerned with its possible environmental impacts. The Bureau of Land Management is currently considering new regulations for well completions on onshore federal minerals. Although these new regulations would not apply directly to private minerals, if they were adopted as a baseline standard for state regulators to imitate, private royalty owners would be affected.[37] Given the large share of production and revenues from privately-owned minerals and the fact that much of the increase in recent oil and natural gas production has employed fracking, the impacts of restrictions on the use of this technology could be huge, with producers and royalty owners bearing the brunt of the costs. Careful, systematic analysis of the impact of such regulatory changes on private royalty income is a promising area for future research.

6. Conclusions

In this study, we use data from various sources to estimate the quantity of domestic oil and natural produced from private minerals as the difference between total production and the

[37] States have already adopted a variety of regulatory strategies (Kulander 2013).

sum of production from federal and 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. From this gross production value, which is generally the basis for payments to private royalty owners, we estimate private royalty income using the (limited) information available on royalty rates in private oil and natural gas leases.

Our calculations suggest that oil and gas royalty payments to private mineral owners are substantial—in 2011 and 2012, we estimate that $21-22 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. 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 deductions and allowances typically made by producers before checks are cut to royalty owners. Nor does it account for taxes paid by royalty owners after they receive the income. 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 royalty income across states. Likewise, we have no way of knowing how royalty income is received across the income distribution. The aggregate demand effects of this income are likely to vary depending on the marginal propensity to consume of royalty recipients. Modifying our royalty income estimates to account for any of these factors would require far more detailed data than are currently available to us.

Our estimates of private royalty income have relevance for several current policy issues related to trade opportunities and restrictions, refinery and pipeline capacity constraints, state and federal tax policies, and restrictions on recently developed production technologies. We suggest that royalty owners would gain from the construction of LNG facilities that would allow the sale of domestic natural gas on the world market. Royalty owners would also likely gain from lifting the ban on oil exports. Domestic refinery and pipeline capacity constraints are both imposing costs on royalty owners, although it is difficult to identify the separate price impacts of the two types of constraints. Increases in state severance tax rates and the elimination of federal tax breaks for royalty owners would both reduce royalty income, as would imposing regulations that restrict the use of fracking technology to produce crude oil and natural gas. For some of these issues we are able to provide rough estimates of the impacts of policy changes on royalty incomes.

The availability of more disaggregated data would make it possible to develop more detailed assessments of private oil and gas royalties. Such data might also allow for sharper focus on the policy issues we discuss in this paper.

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Table 1: Annual Oil and Natural Gas Wells, Production, and Prices in the United States

Year	All Producing	New Wells	Oil Production (MM bbls)	Gas Production (Bcf)	Nominal WTI Spot price $/bbl (annual avg)	Nominal HH Spot Price $/Mcf (annual avg)	Real WTI Spot Price $2012/bbl (annual avg)	Real HH Spot Price $2012/Mcf (annual avg)
2003	755,618	28,851	1,114	15,568	28.47	4.88	34.51	5.91
2004	773,657	32,975	1,094	15,548	37.63	5.46	44.95	6.52
2005	750,982	39,369	1,084	15,795	51.02	7.33	59.50	8.55
2006	781,327	46,223	1,089	16,508	60.22	6.39	69.21	7.34
2007	804,130	46,090	1,097	17,398	67.04	6.25	75.62	7.05
2008	851,204	48,879	1,133	18,798	94.72	7.97	103.33	8.69
2009	824,847	29,278	1,126	19,219	56.65	3.67	60.25	3.90
2010		32,449	1,193	20,137	75.04	4.48	78.84	4.71
2011		32,688	1,358	22,224	95.35	3.95	97.82	4.05
2012			1,705	23,776	94.11	2.66	94.11	2.66

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

Table 2: Total Annual United States Oil and Natural Gas Revenues, 2003-2012

Year	Nominal Oil Revenue	Nominal Gas Revenue	Combined Nominal Revenue
2003	31.71	75.97	107.68
2004	41.17	84.89	126.06
2005	55.31	115.78	171.08
2006	65.57	105.48	171.05
2007	73.54	108.74	182.27
2008	107.32	149.82	257.13
2009	63.77	70.53	134.31
2010	89.49	90.21	179.7
2011	129.45	87.78	217.24
2012	160.45	63.24	223.7

Revenues are reported in billions of nominal dollars

Total 3: 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	26.1
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.

Table 4: Gross Production Revenues from Private Minerals, 2003-2012

Year	Nominal Oil Revenue	Nominal Gas Revenue	Combined Nominal Revenue	Real Oil Revenue ($2012)	Real Gas Revenue ($2012)	Combined Real Revenue ($2012)
2003	24.48	57.21	81.69	29.65	69.45	99.10
2004	32.06	63.87	95.93	38.26	76.46	114.72
2005	43.29	86.79	130.08	50.44	101.40	151.84
2006	50.75	77.98	128.74	58.27	89.66	147.93
2007	57.03	81.19	138.22	64.26	91.58	155.83
2008	82.93	112.22	195.14	90.36	122.39	212.75
2009	48.65	52.05	100.69	51.69	55.40	107.09
2010	67.83	69.07	136.89	71.26	72.65	143.91
2011	98.71	68.6	167.32	101.32	70.48	171.80
2012	123.01	38.61	161.62	123.15	51.38	174.53

Note: Figures are in billions of dollars.

Table 5: 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	146	2,015	2,235	0.935	0.002	0.062
California	10,430	1,457	1,058	31	3,126	323	0.724	0.066	0.210
Oklahoma	3,734	8,355	11	90	1,019	1,832	0.804	0.007	0.190
Louisiana	3,503	7,549	26	164	1,849	1,549	0.755	0.013	0.232
Wyoming	1,432	2,795	1,693	7,213	248	713	0.300	0.632	0.068
New Mexico	1,403	2,555	1,693	5,174	1,299	1,307	0.295	0.511	0.194
Colorado	1,610	5,477	283	1,209	88	63	0.812	0.171	0.017
North Dakota	2,979	228	523	56	1,100	67	0.648	0.117	0.235
Kansas	2,073	1,477	24	39	571	329	0.787	0.014	0.199
Arkansas	320	2,208	0	68	81	385	0.826	0.022	0.152
Utah	887	597	510	948	9	36	0.497	0.488	0.015
Montana	1,721	359	240	157	121	37	0.789	0.151	0.060
Mississippi	1,243	404	19	5	319	69	0.800	0.011	0.188
Ohio	282	467	2	4	72	80	0.826	0.007	0.167
Michigan	359	252	2	10	76	130	0.736	0.015	0.249

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

Table 6: 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 using Montana Royalty Rates**	**Income Share (%) of Total State Income**
Texas	30,294	30,179	60,473	7,559	7,651	0.79
California	10,756	1,119	11,875	1,484	1,584	0.1
Louisiana	3,411	8,330	11,742	1,468	1,443	0.86
Oklahoma	3,990	7,000	10,990	1,374	1,365	1.03
Colorado	2,016	5,089	7,105	888	873	0.41
North Dakota	4,583	173	4,756	594	639	2.15
Wyoming	1,581	2,373	3,954	494	493	1.9
Kansas	2,286	1,101	3,388	423	439	0.39
Arkansas	325	2,975	3,300	413	395	0.43
New Mexico	1,355	1,863	3,218	402	403	0.59
Mississippi	1,452	259	1,711	214	227	0.24
Utah	1,039	645	1,683	210	216	0.24
Montana	1,452	206	1,658	207	220	0.63
Michigan	435	309	744	93	95	0.28
Ohio	277	307	584	73	74	1.77
All States	67,819	69,148	136,967	17,121	17,315	0.14

Note: Units are millions of nominal dollars.

Table 7: Revenue Impacts of Severance Tax Increases

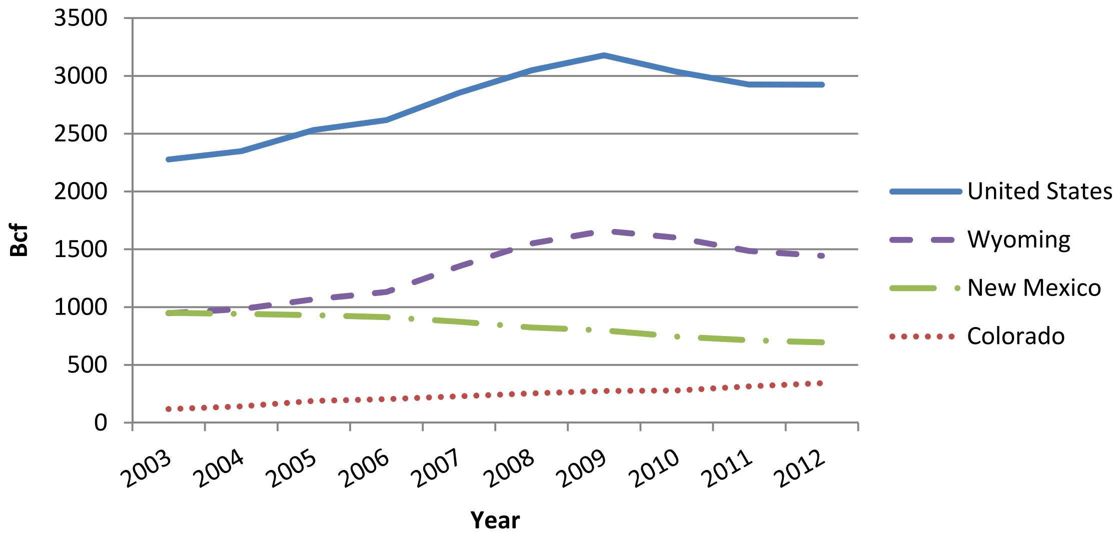
Royalty Rate	
Gas	**11.80%**
Oil	**13.50%**

		Severance Tax Rates		**Private Revenues**			**Private Royalty Income**			**Severance Tax Payments/Revenues**			
State		**Gas**	**Oil**	**Gas**	**Oil**	**Total**	**Gas**	**Oil**	**Total**	**Gas**	**Oil**	**Total**	**Change**
Louisiana*	Current	$0.118	12.50%	$8,330	$3,411	$11,741	$983	$460	$1,443	$219	$58	$277	
	25% Increase	$0.148	15.63%	$8,330	$3,411	$11,741	$983	$460	$1,443	$274	$72	$346	$69.24
	50% Increase	$0.177	18.75%	$8,330	$3,411	$11,741	$983	$460	$1,443	$329	$86	$415	$138.48
Texas	Current	7.50%	4.60%	$30,179	$30,294	$60,473	$3,561	$4,090	$7,651	$267	$188	$455	
	25% Increase	9.38%	5.75%	$30,179	$30,294	$60,473	$3,561	$4,090	$7,651	$334	$235	$569	$113.80
	50% Increase	11.25%	6.90%	$30,179	$30,294	$60,473	$3,561	$4,090	$7,651	$401	$282	$683	$227.60
Wyoming	Current	6.00%	6.00%	$2,373	$1,581	$3,954	$280	$213	$493	$17	$13	$30	
	25% Increase	7.50%	7.50%	$2,373	$1,581	$3,954	$280	$213	$493	$21	$16	$37	$7.40
	50% Increase	9.00%	9.00%	$2,373	$1,581	$3,954	$280	$213	$493	$25	$19	$44	$14.80

Monetary units are in $ millions

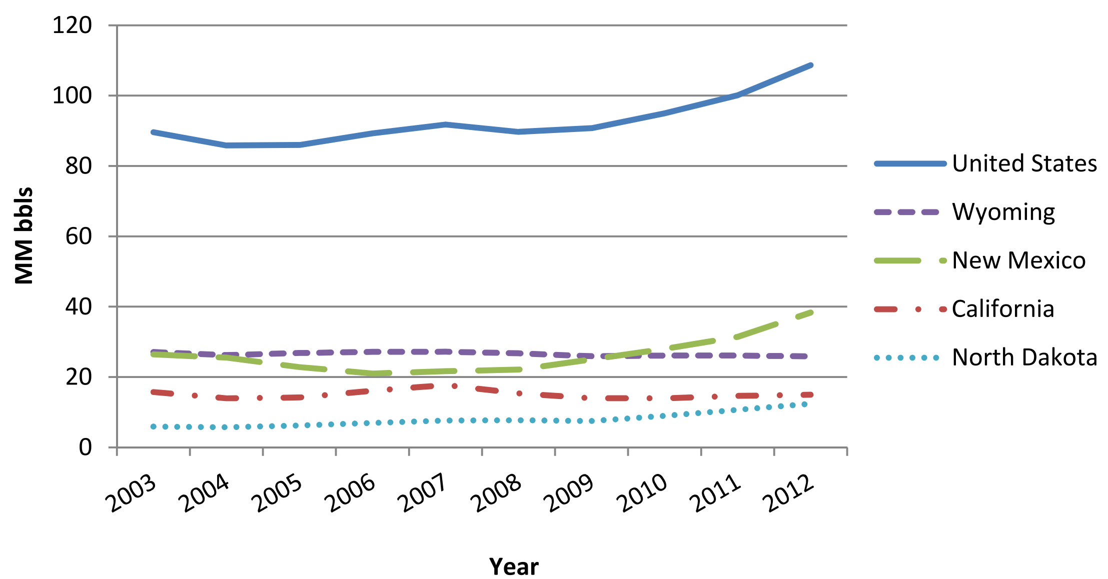
*Gas tax rate for Louisiana is in $/mcf

Figure 1a: Natural Gas Production from Federal Minerals by Major State: 2003 - 2012



Data source: Office of Natural Resource Revenue

Figure 1b: Oil Production from Federal Minerals by Major State: 2003 - 2012



Data source: Office of Natural Resource Revenue

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

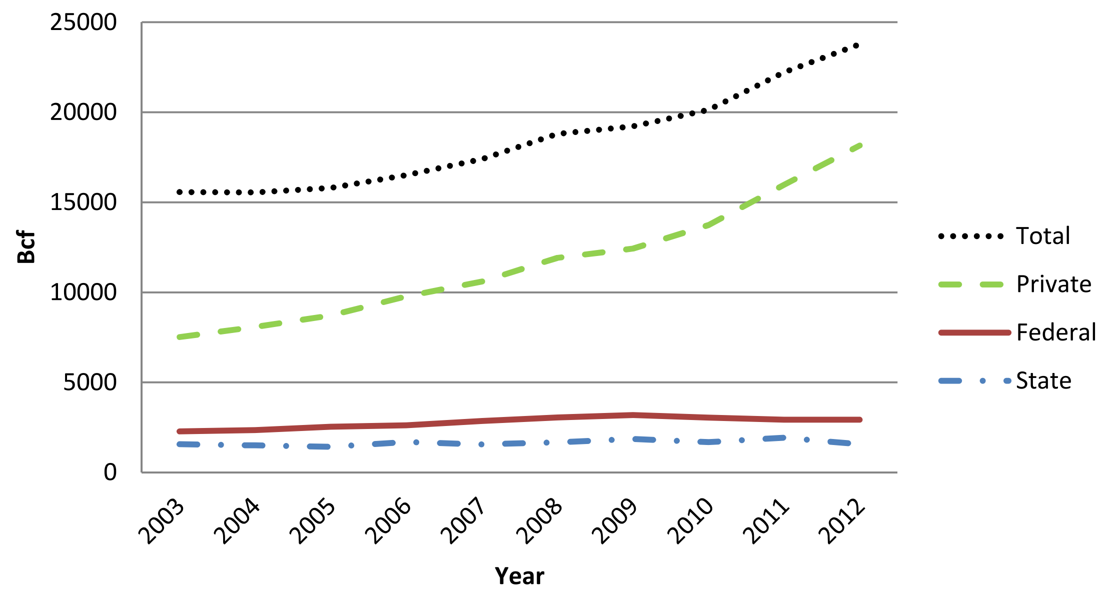


Figure 2b: United States Oil Production by Mineral Ownership Type

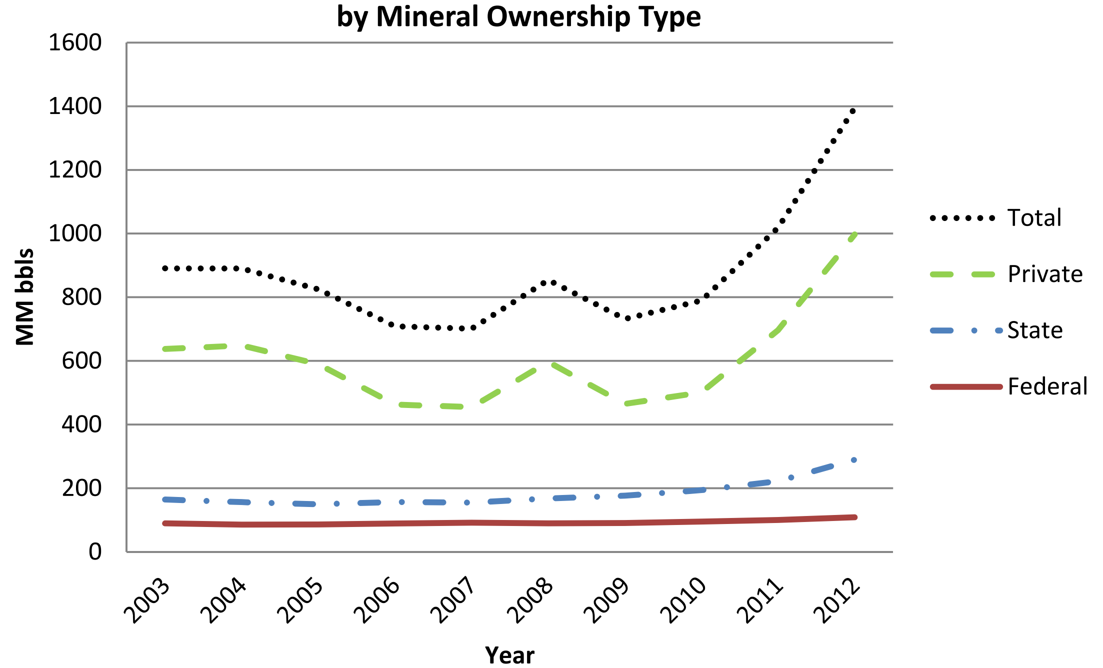


Figure 3: Estimated Aggregate Private Royalty Income by Assumed Royalty Rate United States, 2003 - 2012

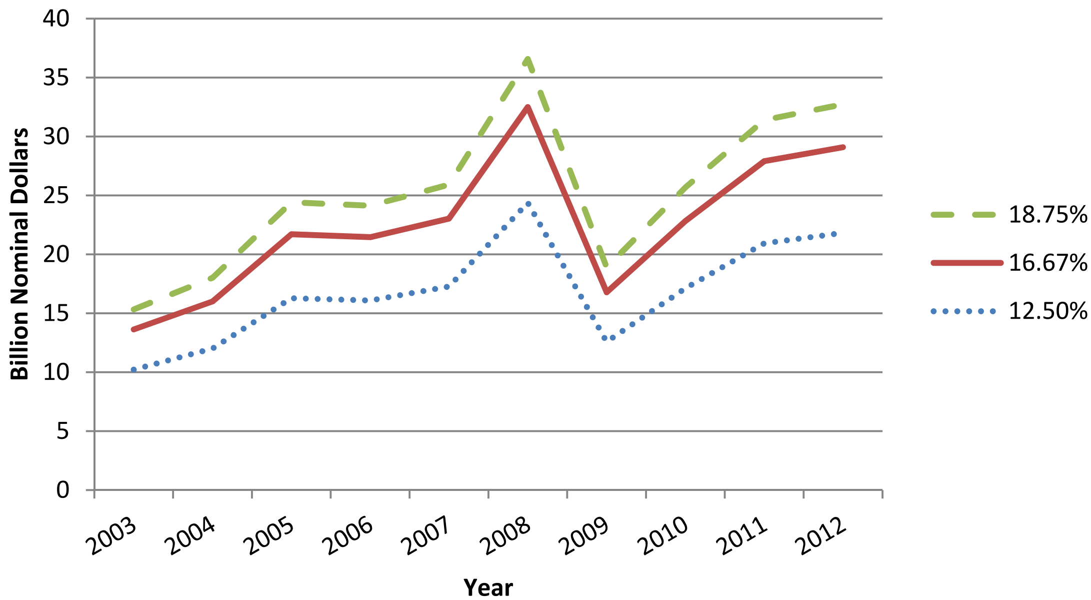
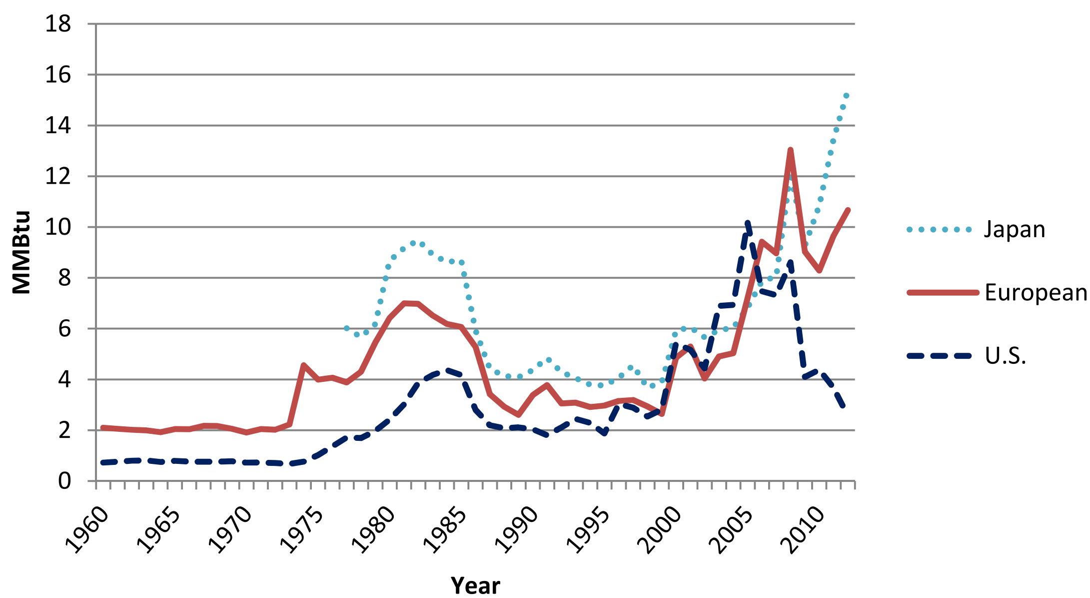


Figure 4: Natural Gas Prices, 1960-2012
U.S., Europe, Japan $2010



Source: World Bank Pink Sheet