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Forecasting New Mexico's Oil and Gas Revenues: The Impact of Technology Change

Gwendolyn Aldrich

THE UNIVERSITY of NEW MEXICO | BUREAU of BUSINESS & ECONOMIC RESEARCH

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INTRODUCTION

Recent technological improvements in horizontal drilling technologies, in particular the development of a steerable GPS-guided bit, have altered New Mexico's oil industry. As a result, patterns in oil revenues are changing and the revenue estimation process used in recent years by the New Mexico State Land Office (SLO) is not performing as reliably as it once did. The SLO has contracted the University of New Mexico's Bureau of Business and Economic Research (BBER) to assist in identifying approaches and methods of forecasting SLO revenues from oil and gas renewable sources (i.e., bonus payments) and non-renewable sources (royalty income).

HISTORY OF HORIZONTAL DRILLING

The first horizontal oil well was completed in Texas in 1929, but the technology had little practical application until sufficient technological improvements in the realms of downhole drilling motors and telemetry equipment[1] made the technology commercially viable in the 1980s (Helms, 2008). The ability to drill longer laterals (lengths increased from 400 feet to more than 8,000 feet) resulted in a second generation of horizontal drilling. A third generation occurred as a result of the ability to drill multiple longer, deeper, and more accurately placed horizontal well bores. Advances in horizontal drilling, especially when combined with multi-stage hydraulic fracturing technology, have been key to opening new areas for oil and gas development and in the rediscovery of older developments.

The economic viability of horizontal drilling is still in question and depends upon the specific site and application. Because most oil and gas reservoirs are more extensive in the horizontal plane than in the vertical plane, a horizontal well provides access to a larger portion of the reservoir than a vertical well. Horizontal drilling can increase productivity by enabling the intersection of multiple fracture systems and by delaying water or gas intrusion to oil production. Horizontal oil well yields are usually 2 to 7 times greater than that of vertical wells (Matthews, 2011), returns on investment associated with horizontal wells have been markedly higher than those of vertical wells, and after-tax return rates have increased as technology has improved (DOE Energy Information Administration, 1993).

The U.S. Energy Information Administration estimates that a horizontal well can cost between 25 and 300 percent more than a vertical well to drill and complete, but that despite higher drilling and completion costs, horizontal drilling has been successful and profitable in numerous areas (DOE Energy Information Administration, 1993). Production rates and returns on investment associated with horizontal wells have been markedly higher than those associated with vertical wells, and after-tax return rates have increased as technology has improved. The technology has also reduced the portion of North Dakota's dry (non-producing) wells from approximately 22 percent to 1 percent (Strombeck, 2011). Conversely, Berman (2009) finds that decline curves for horizontal wells in the Barnett shale are too optimistic. Berman states that horizontal wells in the Barnett Shale typically have a short commercial life and ultimately yield recoverable reserves that are essentially the same as those for vertical wells.

Horizontal drilling is still too much in its infancy to develop a meaningful and complete assessment of where, when, and how it might play a profitable and critical role in oil and gas development. The success of horizontal wells (or lack thereof) is clearly dependent upon numerous factors, including location, the area's production history, application specifics, etc.

[1] Telemetry equipment enables remote measurement and reporting of information.

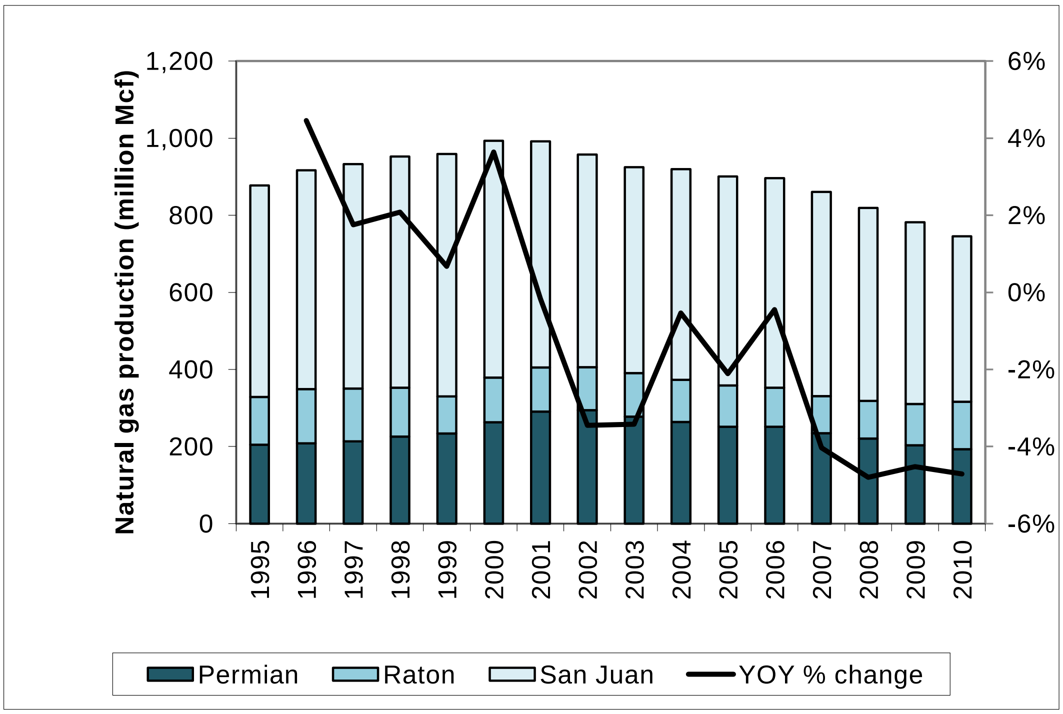
NEW MEXICO OIL AND GAS

Oil and gas have been commercially produced in New Mexico since the 1920s. Development of the NM oil and gas industry and the influence on the industry of recent developments in horizontal drilling technology are discussed below.

HISTORY OF PRODUCTION AND PRICES

Commercial natural gas production began in New Mexico during the 1920s and steadily increased until low natural gas prices in the 1970s caused a significant decrease in production. Coalbed methane was discovered in the Fruitland Formation of the San Juan Basin during the late 1980s, resulting in increased production. Natural gas production has slowly declined in recent years. The majority of gas production currently comes from the San Juan Basin, with significant quantities also produced from the Permian and Raton basins (Figure 1).[2]

Figure 1. NM natural gas production, 1995-2010



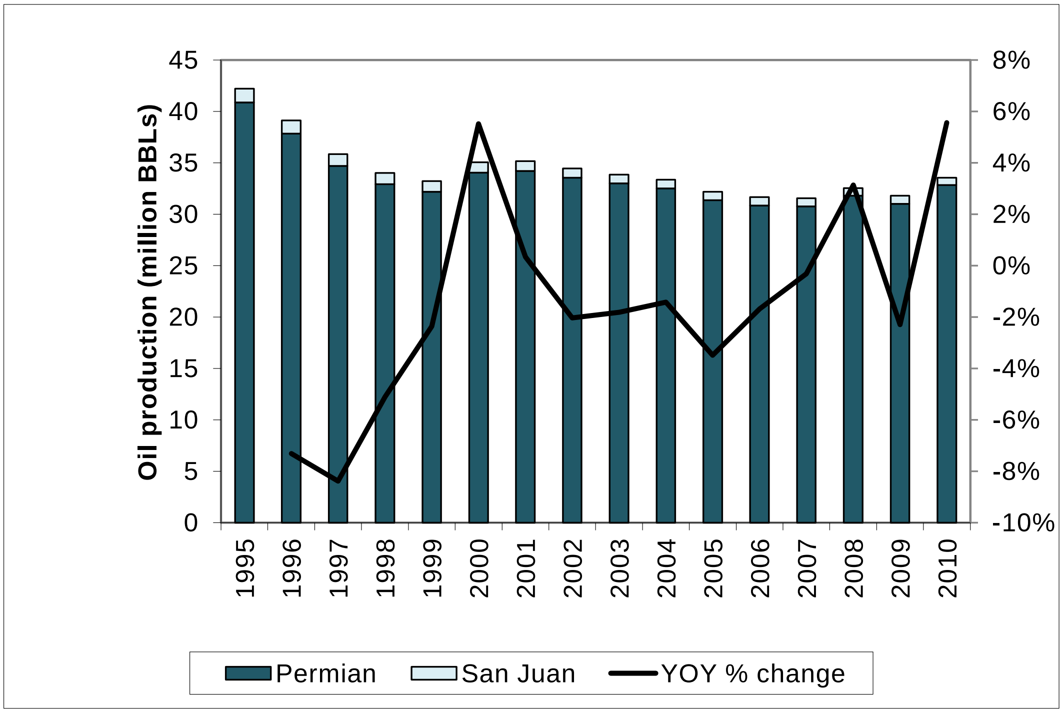
Source: Compiled by BBER using ONGARD data

New Mexico oil production also began during the 1920s. Production increased steadily, peaked in 1969 at 129 million barrels, and subsequently declined steadily through the late 1970s, at which time oil embargoes and high oil prices created incentives to increase drilling (Broadhead 2003). Oil prices fell again in the mid-1980s, reversing the incentive to drill. Oil production in New Mexico has remained nearly constant from the 1990s to 2010 due to

[2] For the purposes of this report, Oil and Natural Gas Administration and Revenue Database (ONGARD) product codes are categorized as either oil or gas; oil, oil condensate, oil (other liquid hydrocarbons), and lost oil are categorized as oil, whereas processed gas, gas (wet), gas plants' products, gas (lost, flared, or vented), and CO_2 are categorized as gas.

(1) the discovery of new plays, (2) reworking older wells, (3) development of the Dagger Draw field in Eddy County, and (4) new technologies (Figure 2).

Figure 2. NM oil production, 1995-2010 (Source: Compiled by BBER using ONGARD data)

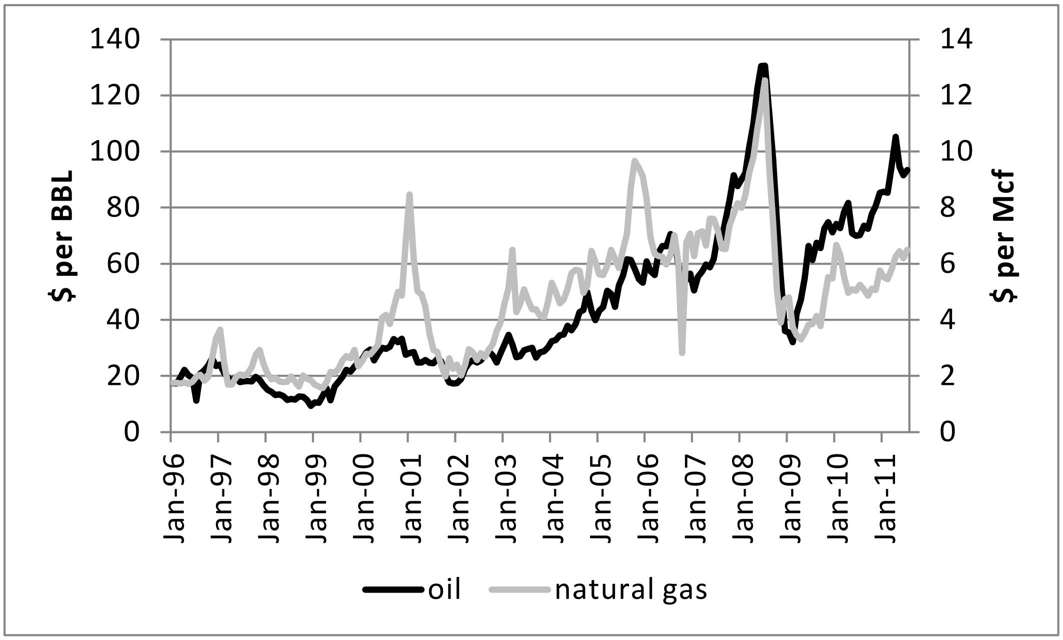


Source: Compiled by BBER using ONGARD data.

Weighted average prices received for NM oil and natural gas products are depicted in Figure 3.[3] While both oil and natural gas prices have in general had an upward trend, natural gas prices have been more volatile than oil prices. As a result of the discovery of coalbed methane and the increase in natural gas prices, the value of natural gas produced in NM has increased exponentially from $1.5 billion in the early 1990s to over $6 billion a decade later (Figure 4). Rising oil prices caused the value of New Mexico's produced oil to increase as well, from $1.5 billion in 1990 to $2 billion in 2000 (Broadhead, 2003).

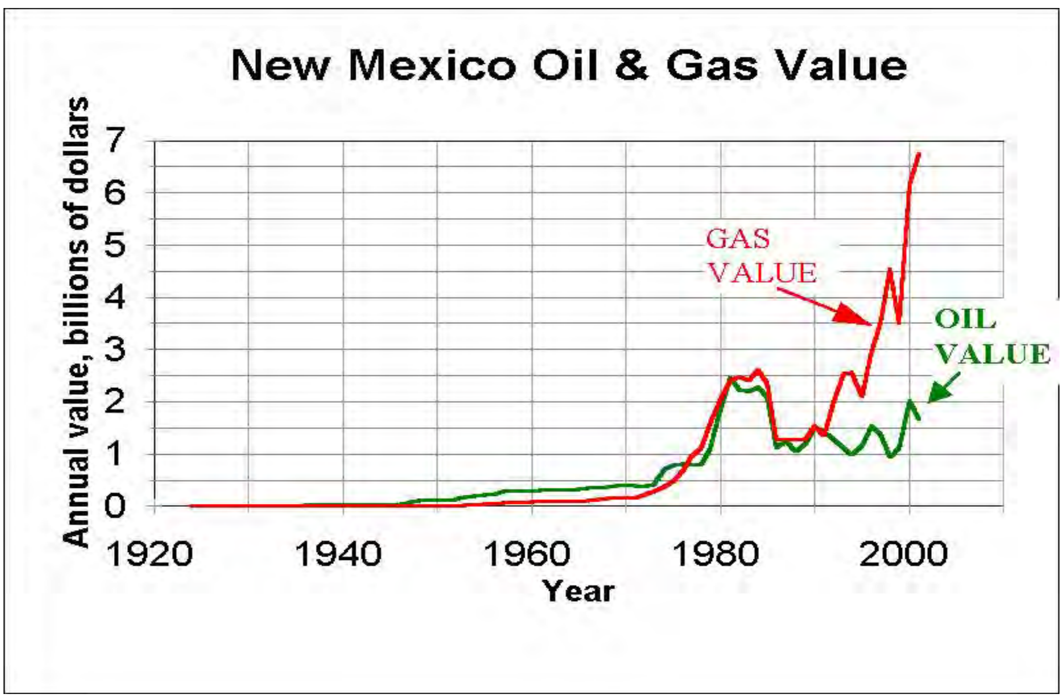
[3] Depicted prices are weighted averages of the prices received for various natural gas products or oil products.

Figure 3. NM oil and natural gas prices, 1996-2011[4]



Source: Compiled by BBER using the NM Taxation and Revenue Department's ONGARD County Volume and Value Reports.

Figure 4. Value of NM oil and gas, 1920s-2001



Source: Broadhead, 2003

[4] A smaller set of product codes was used in the price analysis than in other analyses presented herein; the price analysis included product codes 1 (oil), 2 (oil condensate), 3 (processed gas), 4 (wet gas), and 7 (gas plants' products).

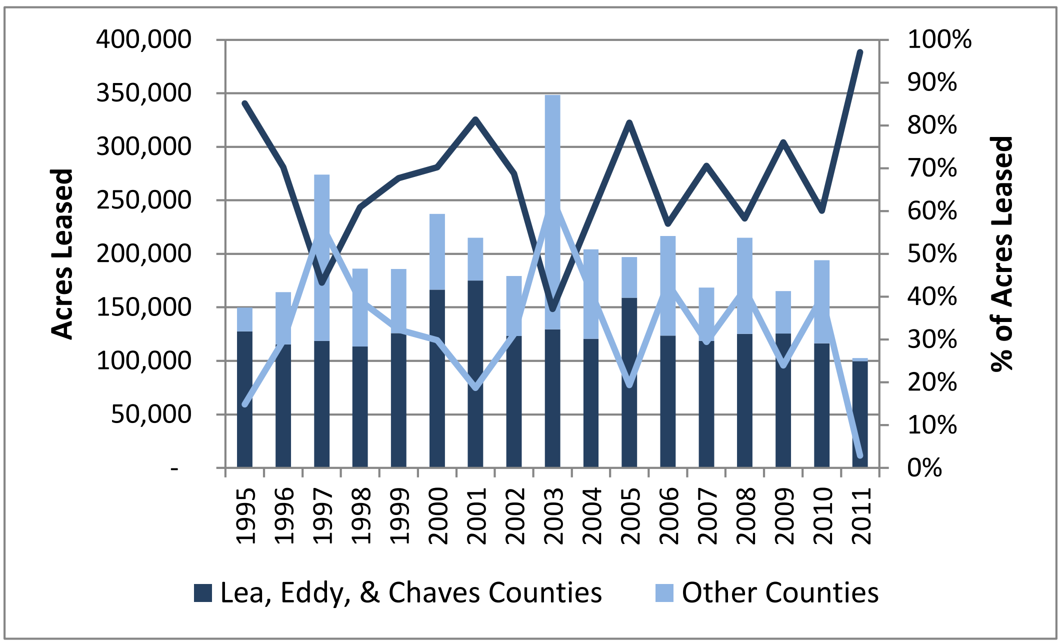
REVENUES

The SLO receives oil and gas revenues in the form of bonus payments, annual rental payments, and royalties. Bonus payments and royalties are the largest oil and gas revenue sources, and are thus the focus of current efforts to improve revenue forecasting procedures.

BONUS PAYMENTS

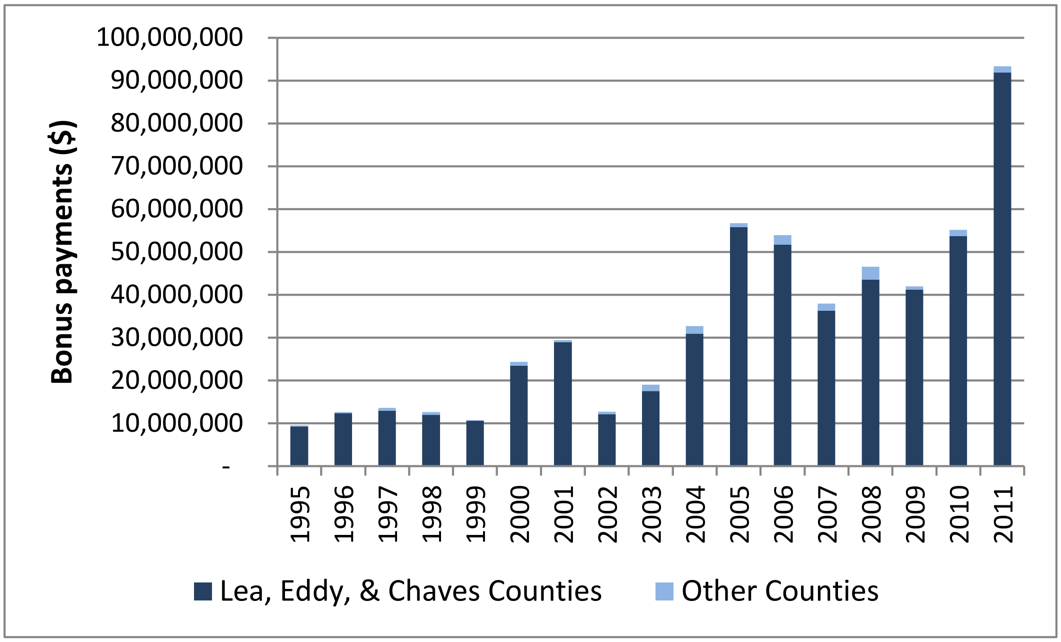
Approximately 13 and 31 percent of NM state trust lands are located within the San Juan and Permian Basins, respectively. Because the San Juan Basin is almost entirely leased, Lea, Eddy, and Chaves Counties (located within the Permian Basin) are of significant importance in terms of the number of acres leased (Figure 5). Lea, Eddy, and Chaves Counties are of even greater importance in terms of bonus payment revenues (Figure 6); Lea County leases are on average responsible for 60 percent of state-wide bonus payments, while Eddy and Chaves Counties on average account for 26 and 11 percent, respectively.

Figure 5. Acres leased by NM SLO, 1995-2011



Source: Compiled by BBER using ONGARD data.

Figure 6. NM bonus payments, 1995-2011[5]

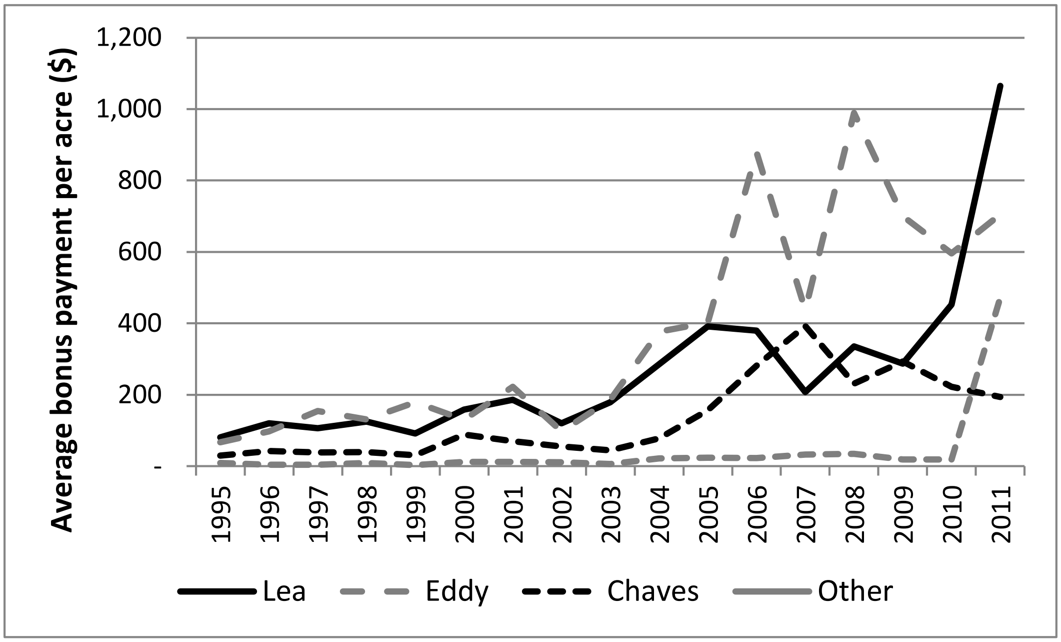


Source: Compiled by BBER using ONGARD data.

Between 1994 and the early part of this century, bonus payments averaged less than $200 per acre, with bonus payments from Lea, Eddy, and Chaves Counties consistently higher than those in other areas of the state (Figure 7). During the past decade, per-acre bonus payments in these three counties (and in particular Eddy County) have increased dramatically. State-wide average per-acre bonus payments reached a record high in 2011, jumping from $284 per acre in 2010 to $908 per acre in 2011. Average per-acre bonus payments for tracts in Lea County increased to nearly $1,100.

[5] At the time this analysis was compiled, bonus payment data were available only through September, 2011. Although data for 2011 is therefore incomplete, we nevertheless include 2011 in this and other bonus payment graphs to illustrate the dramatic increase in bonus payments that has occurred this year.

Figure 7. Per-acre bonus payments, 1995-2011



Source: Compiled by BBER using ONGARD data.

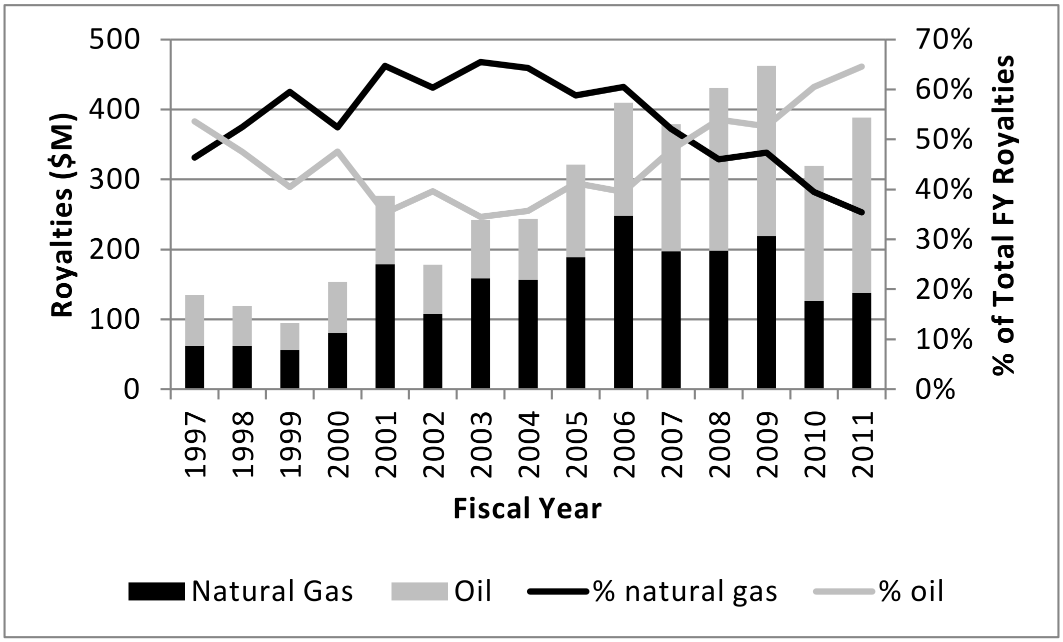
This very recent and rapid rise in per-acre bonus payments has occurred as a result of changes in horizontal drilling technology and the associated lease of tracts that were formerly restricted. Portions of the Permian Basin have been closed to oil and gas drilling until very recently when advances in horizontal drilling (in particular, a GPS-guided steerable bit) have mitigated concerns regarding the area's potash deposit. Beginning in June 2011, the SLO was able to offer for lease previously restricted tracts located in oil-rich regions of Lea and Eddy Counties. June, July, and August were therefore record-setting months, with bonus payments of $17, $19, and $16 million, respectively. (In contrast, bonus payments received by the SLO in a typical month average between $3 and $6 million.)

Bonus payments are an indicator of oil and gas companies' production and revenue expectations. Large bonus payments received by the SLO during the summer of 2011 indicate that oil companies expect significant production from horizontal wells in Lea and Eddy Counties.

ROYALTIES

Royalties paid to the state of New Mexico have increased from less than $100 million in fiscal year (FY) 1999 to nearly $400 million in FY2011, and peaked at more than $450 million in FY2009 (Figure 8). In FY2003, approximately 65 percent of royalties resulted from natural gas production and only 35 percent resulted from oil production. Today the relative importance of oil and natural gas is reversed, with 65 percent of NM royalties now derived from oil production.

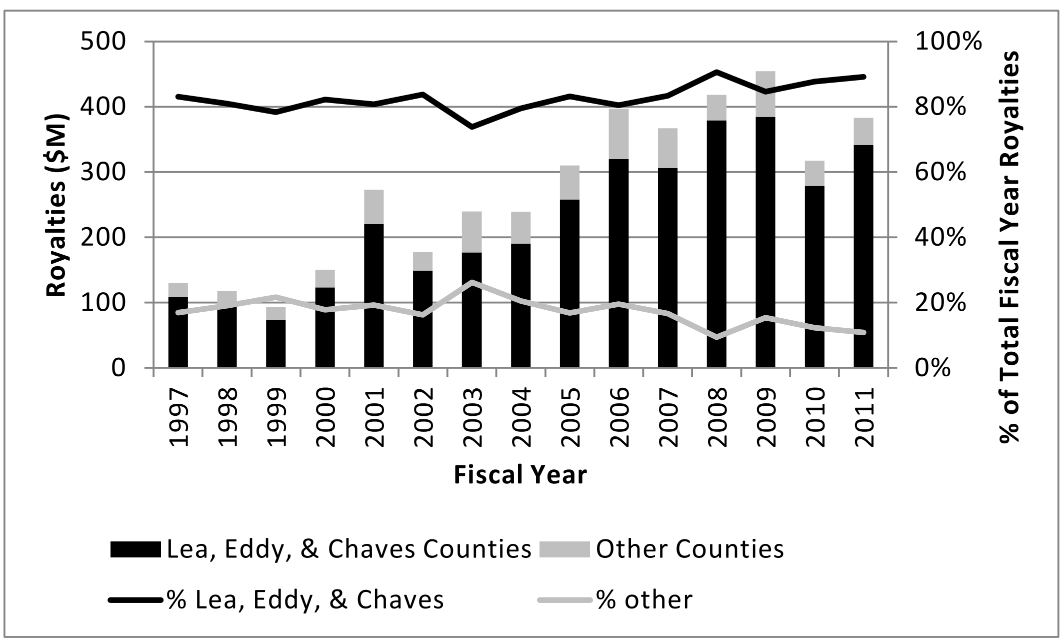
Figure 8. NM oil and gas royalties, FY1997–FY2011



Source: Compiled by BBER using ONGARD data.

Since 1997, Lea, Eddy, and Chaves Counties have generated approximately 80 percent of New Mexico's oil and gas royalties (Figure 9). Lea County is responsible for the majority of royalties from the Lea/Eddy/Chaves County area, although since 1997 the portion of New Mexico royalties resulting from Lea County has declined gradually while the portion derived from Eddy County has grown proportionately.

Figure 9. Royalties: Relative importance of Lea, Eddy, & Chaves Counties, 1997-2011



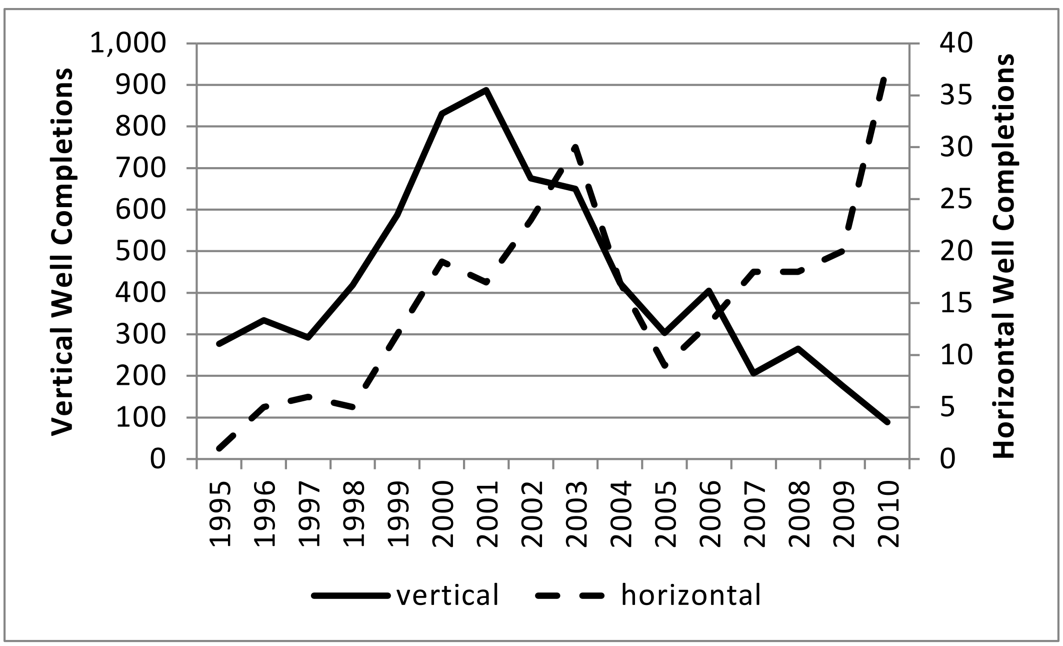
Source: Compiled by BBER using ONGARD data.

TECHNOLOGY CHANGE

As discussed in the previous subsection, horizontal drilling has had a significant impact on New Mexico's oil and gas bonus payment revenues. Although evidence suggests that horizontal well technology is especially beneficial when coupled with multi-stage hydraulic fracturing (which has been used for years in both vertical and horizontal wells), data from ONGARD can be used to determine well-type (i.e., vertical or horizontal), but cannot be used to ascertain whether hydraulic fracturing is used. The NM Oil Conservation Division (OCD) collects data regarding the use of fracturing fluids on their C-105 form[6], but the information is not input to ONGARD and is therefore unavailable for modeling and forecasting purposes. We thus focus our discussion and research on horizontal drilling. This section provides an analysis of horizontal wells in New Mexico – how the prevalence of horizontal wells has changed over time, and the implications for production and royalties.

ONGARD data pertaining to wells' surface and bottom hole locations are used to ascertain whether wells are vertical or horizontal. If a well's surface and bottom hole location are in the same range, township, section, and/or unit letter, then the well is assumed to be a vertical well. Alternately, if a well's surface and bottom hole location are in a different range, township, section, and/or unit letter, then the well is assumed to be a horizontal well. Not surprisingly, vertical wells are drilled and completed far more frequently than horizontal wells. Whereas relative changes in the frequency of vertical and horizontal well completions were similar between 1995 and 2006, since 2006 the number of vertical well completions has declined while that of horizontal wells has increased (Figure 10). As depicted in Table 1, horizontal wells comprise a small portion of New Mexico oil and gas wells – out of nearly 30,000 oil and gas wells, fewer than 1,300 have been drilled horizontally. Horizontal wells are most prevalent in the San Juan Basin where they comprise 6.7 percent of wells, and are least prevalent in the Raton Basin where they comprise less than 1 percent of wells.

Figure 10. Vertical and horizontal well completions, 1995-2010



Source: Compiled by BBER using ONGARD data.

[6] The OCD's C-105 form can be found at http://www.emnrd.state.nm.us/ocd/documents/C-10520110801.pdf.

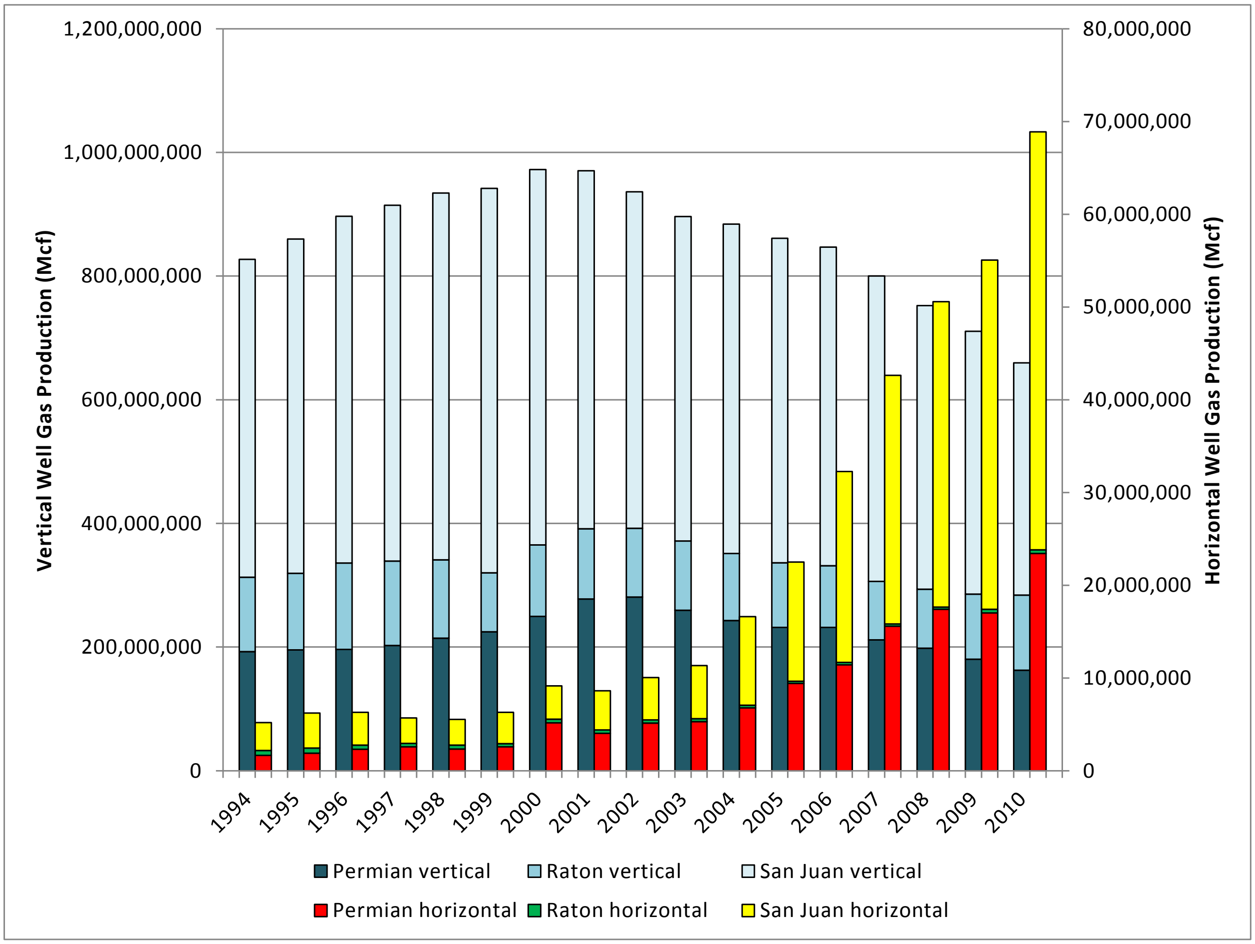
Table 1. Distribution of horizontal and vertical wells, by county and basin

Basin/County	Vertical		Horizontal		Total
	Number	Percent	Number	Percent	
Permian					
Chaves	1,386	97.3%	39	2.7%	1,425
Eddy	5,468	94.2%	337	5.8%	5,805
Lea	10,066	98.5%	150	1.5%	10,216
Roosevelt	176	99.4%	1	0.6%	177
Total	***17,096***	***97.0%***	***527***	***3.0%***	***17,623***
San Juan					
McKinley	71	97.3%	2	2.7%	73
Rio Arriba	6,179	92.1%	528	7.9%	6,707
San Juan	3,890	95.1%	202	4.9%	4,092
Sandoval	12	100.0%	0	0.0%	12
Total	***10,152***	***93.3%***	***732***	***6.7%***	***10,884***
Raton					
Union	330	99.4%	2	0.6%	332
Harding	252	99.6%	1	0.4%	253
Total	***582***	***99.5%***	***3***	***0.5%***	***585***
Total	**27,830**	**95.7%**	**1,262**	**4.3%**	**29,092**

Source: Compiled by BBER using ONGARD data.

Figure 11 depicts natural gas production levels from New Mexico's vertical and horizontal wells from 1994 through 2010. Natural gas production from horizontal wells is minimal compared to that from vertical wells, but began increasing exponentially in the early part of the millennium; whereas horizontal wells were responsible for the production of a mere 9 million Mcf of natural gas in 2000, horizontal well production in 2010 was nearly 69 million Mcf (a 653 percent increase). While production from horizontal wells has increased exponentially in recent years, that of vertical wells has decreased.

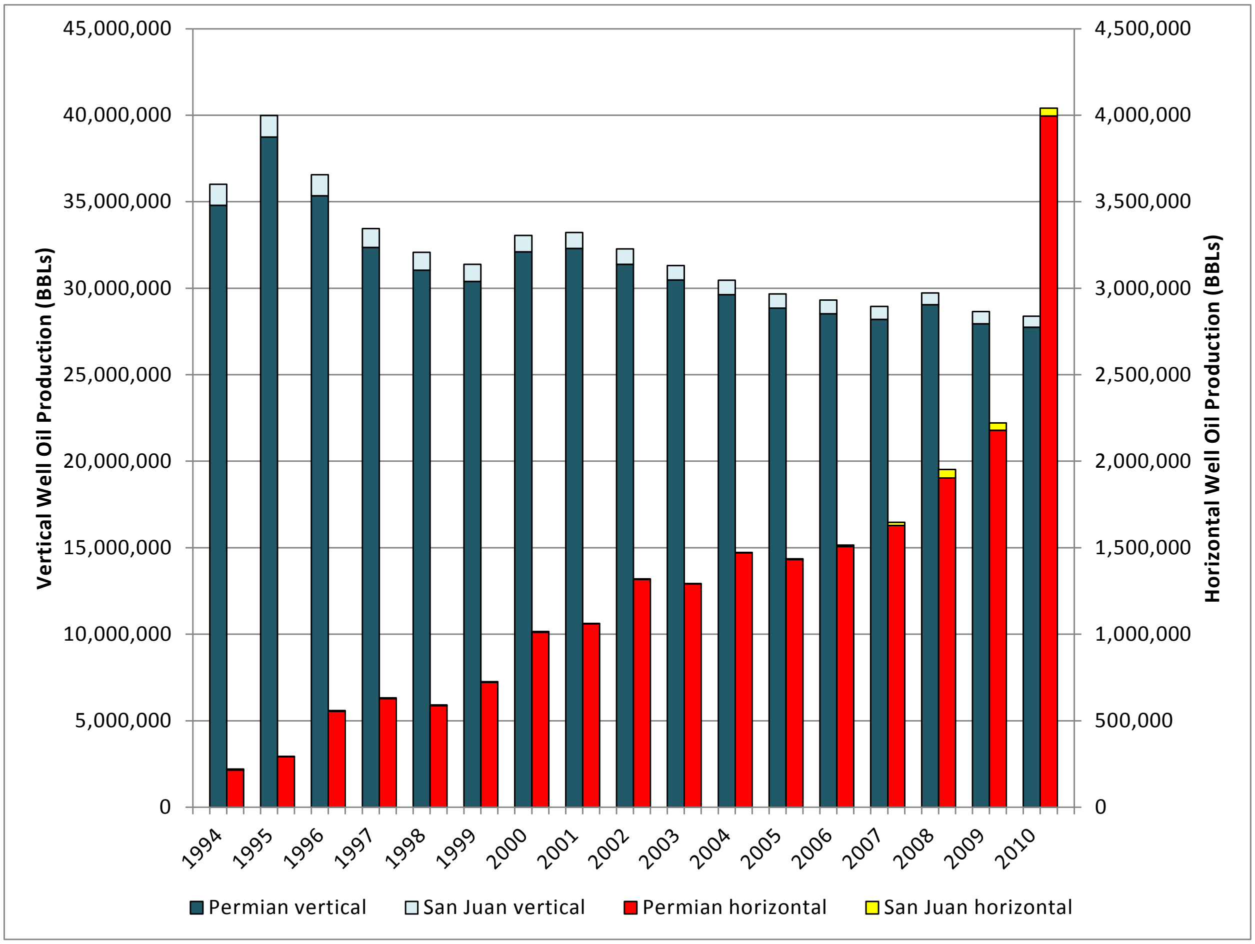
Figure 11. Gas production from horizontal and vertical wells, 1994-2010



Source: Compiled by BBER using ONGARD data.

A similar story holds true for oil production. The amount of oil produced from horizontal wells has increased steadily since 1994 (Figure 12), and increased sharply between 2009 and 2010. At the same time, oil production from vertical wells has slowly declined.

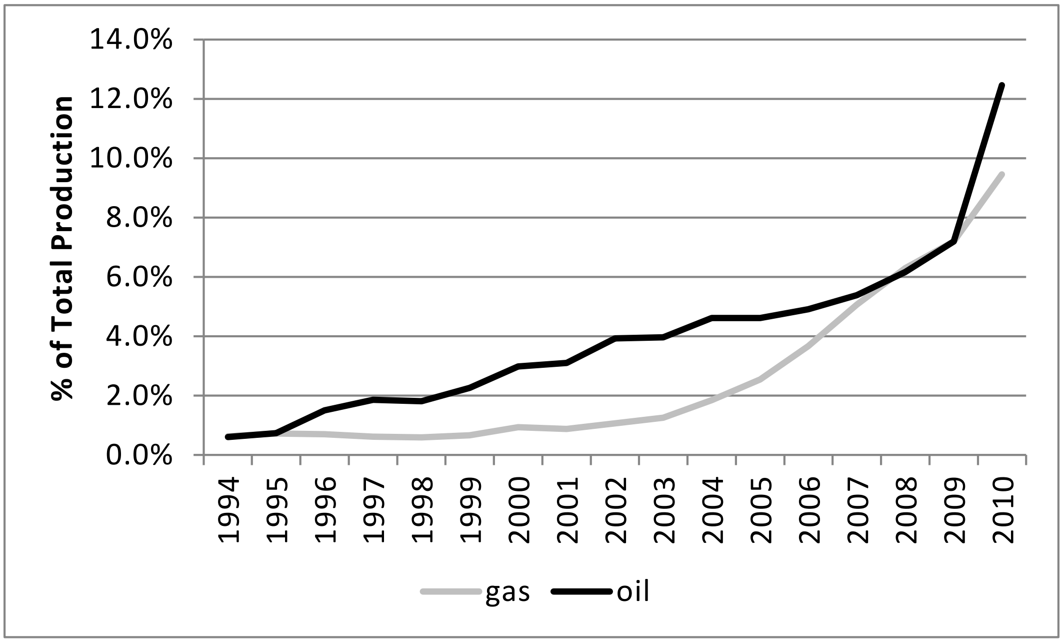
Figure 12. Oil production from horizontal and vertical wells, 1994-2010



Source: Compiled by BBER using ONGARD data.

In 1994, horizontal wells contributed less than one percent of total natural gas and oil production. The portion of oil and natural gas produced using horizontal wells has increased over time such that in 2010 horizontal wells contributed 9.5 and 12.5 percent of natural gas and oil production, respectively (Figure 13).

Figure 13. Percent of total production from horizontal wells, 1994-2010



Source: Compiled by BBER using ONGARD data.

OTHER STATES' OIL AND GAS REVENUE FORECAST METHODS

The reliability of the five-year moving average model used by the New Mexico SLO to forecast oil and gas revenues has been declining. It is expected that the increased incidence of horizontal drilling has been at least in part responsible for this change. Recent developments in the Permian Basin (i.e., the leasing of previously restricted tracts) suggest that the ability of a five-year moving average model to accurately predict future SLO revenues is likely to erode further. Understanding how horizontal drilling technologies are affecting NM oil and gas revenues may have important implications for developing more accurate forecasts of NM oil and gas revenues. As a first step in developing a new modeling approach, we assess the experiences of other states with horizontal drilling. Below is a discussion of production forecast methods used by personnel in other states, historical horizontal drilling and production in these states, and how (if) horizontal drilling is being accounted for in their forecast methods.

BONUS PAYMENTS

As a result of the inability and/or difficulty in predicting bonus payments, revenue forecasters in other states either do not forecast bonus payments or have very simplistic methods for doing so. For example, personnel in the Colorado Governor's Office of State Planning and Budgeting are responsible for forecasting bonus payments associated with federal mineral leasing (FML) activities. However, because bonus payments follow a seemingly random walk, they forecast this revenue source by calculating the prior year's bonus payments as a percent of total revenues and projecting that percentage forward (Schrock, 2011). Colorado Legislative Council staff estimate total FML revenues as a function of natural gas prices and divide the FML revenue forecast into bonus payment and non-bonus payment portions based upon historical shares (Carey, 2011).

Employees of the Montana Minerals Management Bureau project bonus payments, but do not use a formal model. Rather, conservative quarterly projections are made for the upcoming fiscal year based upon recent sales information. If a large sale occurred in the recent past, such information is omitted when making projections; i.e., the Bureau assumes another large sale will not occur. The legislature occasionally asks for a three-year forecast, in which case the Bureau holds the forecast constant for all three years (Mason, 2011). The Wyoming Office of State Lands & Investments indicates that they have not found an effective method for projecting bonus payments and therefore make no such projections (Bracht, 2011).

ROYALTIES, PRODUCTION TAXES, SEVERANCE TAXES, ETC.

COLORADO

Fluctuations in Colorado's oil and gas severance tax revenues have historically been driven by prices changes, as production has been relatively flat. Natural gas generates the vast majority of Colorado's severance tax revenues, and if the natural gas price forecast is fairly accurate, then the Colorado severance tax forecast will also be fairly accurate (Schrock, 2011). Recently, however, horizontal drilling in the Niobrara Shale has resulted in record bonus payments and increased oil royalties. Because it is unclear how horizontal drilling will affect production, decline curves, and royalties, there is uncertainty regarding how to incorporate this technology into forecast models (Milonas, 2011).

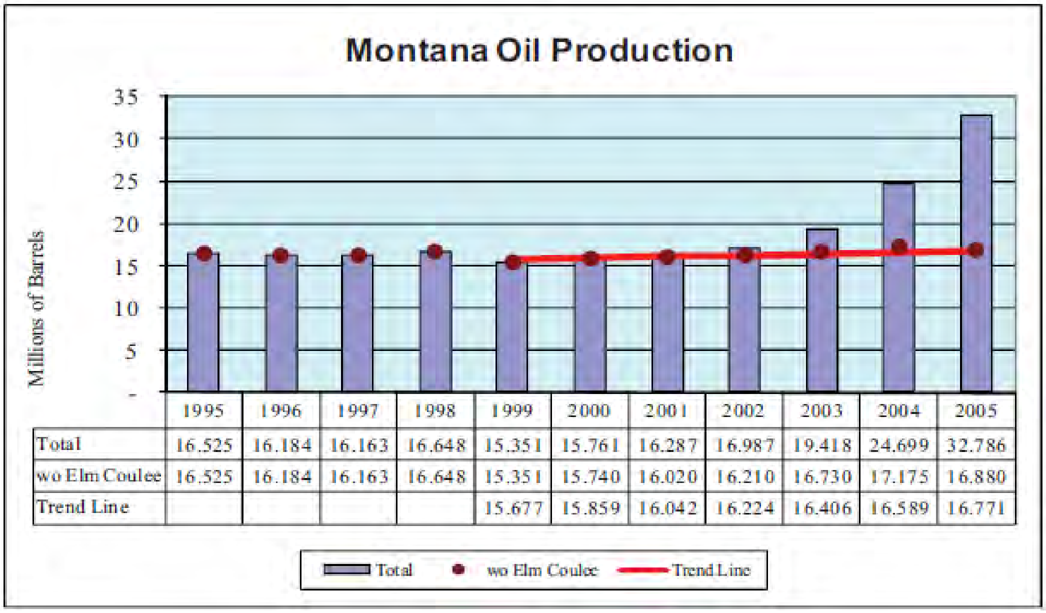
The Colorado Governor's Office of State Planning and Budgeting develops revenue forecasts for the governor. Forecasts are developed for the current year and two additional years, although forecasts beyond the current year are typically not very reliable due to price volatility. Because oil and gas companies can claim a credit for 85 percent of the company's property taxes against their severance tax liability, and because property tax rates vary by county, the Office of State Planning and Budgeting forecasts revenues at the county level. Production is forecast at the county level by applying trend analysis to historical production data. Results are adjusted based upon knowledge of where rigs are operating in the state and thus where drilling activity is likely to occur.

The Colorado Legislative Council Staff develops revenue forecasts for the legislature. County-level oil and gas production forecasts are developed by applying a ten-year average annual decline (or growth) rate to the most recently available annual production data. The product of the state-level price forecast and the county-level production forecast yields a county-level forecast of gross value, which is subsequently adjusted to account for property tax credits and stripper wells, which are taxed at a lower rate (Carey, 2011).

MONTANA

Between 2003 and 2006 oil production in the Bakken Formation's Elm Coulee Field grew exponentially, whereas production in the remainder of the state held fairly constant (Figure 14). As a result the Elm Coulee Field is currently responsible for approximately half of Montana's oil production. Drilling in the Elm Coulee Field has been almost exclusively horizontal, and the decline in production appears to occur faster than in other areas (Dale, 2011). As a result, Elm Coulee Field production and revenue estimates are developed separately from those of other areas.

Figure 14. Montana oil production, 1995-2005



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total	16.525	16.184	16.163	16.648	15.351	15.761	16.287	16.987	19.418	24.699	32.786
wo Elm Coulee	16.525	16.184	16.163	16.648	15.351	15.740	16.020	16.210	16.730	17.175	16.880
Trend Line					15.677	15.859	16.042	16.224	16.406	16.589	16.771

Source: Montana Legislative Fiscal Division, 2011

Analysts in Montana's Office of Budget and Program Planning disaggregate oil and gas production data by tax category, which varies by product, production method, age of well, type of well (horizontal or vertical), prior year's production, WTI crude oil price, and interest.[7] Oil production forecasts are developed for each geographic area and tax category, while natural gas production forecasts are only estimated for each tax category. (Because natural gas production characteristics are rather homogeneous across the state of Montana, state-wide models are used to project natural gas production.) In all cases quarterly production volumes are modeled as a function of historical production volumes.

To forecast oil production, the Montana Legislative Fiscal Division develops field-level models for the Elm Coulee Field and ten other major fields, while production from all other areas is modeled jointly. Normalized decline curves, which represent average production by the age of well (in months), are developed for the Elm Coulee, each of the other ten major fields, and all other areas. The normalized decline curves are applied (by tax category) to each existing well and to an estimate of wells to be drilled in the future. Legislative Fiscal Division staff notes that normalized decline curves are quite accurate after peak production, and that errors in their revenue forecasts typically stem from errors in the price forecast rather than errors in the production forecast (Johnson, 2011).

Natural gas models are developed in a similar fashion. Normalized decline curves are estimated for each of eight fields responsible for the recent increase in production as well as for the remainder of the state. Production is forecast by applying the normalized decline curves to each existing well and to an estimate of spudded wells.

[7] Interest refers to whether the tax payer is a working interest owner (and therefore shares in a well's costs) or a royalty recipient.

NORTH DAKOTA

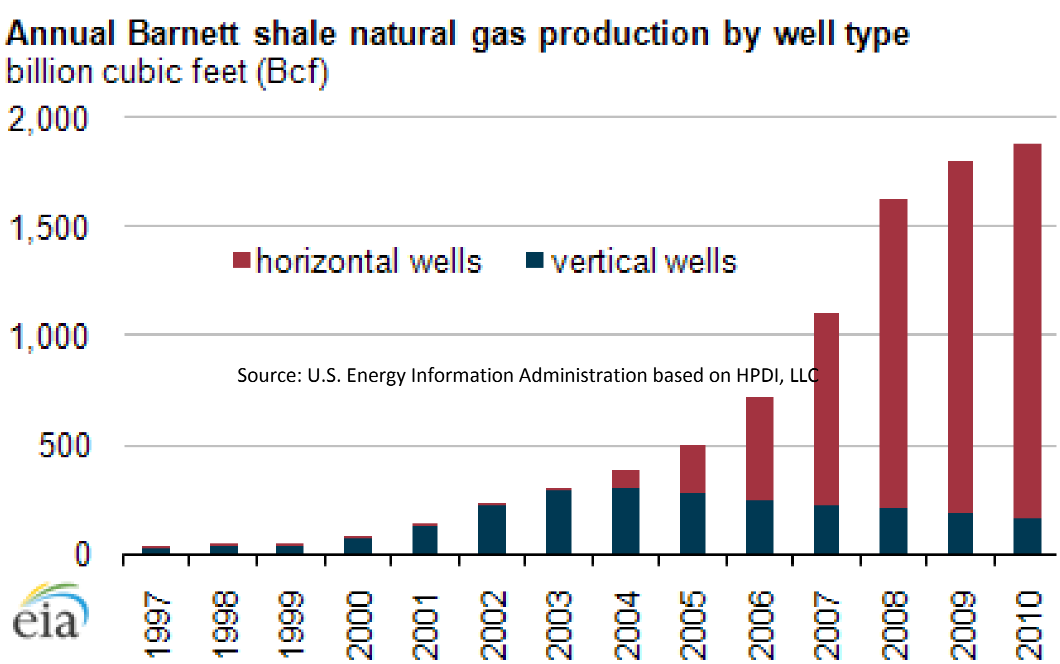
Horizontal drilling began in North Dakota in 1987 and has become a major factor in the development of North Dakota's Bakken Formation. Horizontal wells have become more common since 2000; nearly all North Dakota wells are now horizontally drilled. Analysts have found that decline curves associated with the horizontal wells are much steeper than those associated with vertical wells, with most production occurring within the first 18 months.

Because nearly all North Dakota wells are now horizontally drilled, the process used by the North Dakota Office of the State Tax Commissioner to forecast revenues has changed dramatically. The significant heterogeneity that was previously present (with respect to both technology and type of well) required nearly a well-by-well forecasting approach. Decline curves for the wells in a particular field and formation were averaged and the result used as the decline curve for that field and formation. However, because technology and well-type are now nearly homogeneous, research analysts currently use much more of a macro approach when forecasting oil and gas revenues; a well-by-well approach is no longer necessary.

TEXAS

Beginning in the late 1990s horizontal wells began to play an important role in natural gas production from the Barnett Shale, and now clearly dominate (Figure 15); between 2004 and 2010 the number of horizontal wells in the Barnett Shale grew from fewer than 400 to more than 10,000 (DOE Energy Information Administration, 2011).

Figure 15. Importance of horizontal wells in Barnett shale natural gas production



Source: DOE Energy Information Administration, 2011

The Texas Comptroller of Public Accounts is responsible for forecasting oil and gas revenues, but office personnel indicate that the area is so dynamic that a new model is developed each year (Pham, 2011); oil and gas revenues are not forecast using a given model or approach. Factors that are considered when developing the model each year include relative oil and gas prices, technology, drilling rig counts (vertical, horizontal, oil, and gas), relative strength of the US dollar and the Euro, global economies, weather, pipelines and market scale, oil and gas companies' cost structures and input costs, and US and global geopolitics.

WYOMING

The Consensus Revenue Estimation Group forecasts production levels by applying historical decline rates to recent production data and making necessary adjustments to account for information obtained from various information sources and industry contacts. However, when potential adjustments are highly speculative, no adjustments are made (Grenvik, 2011). For example, when new areas of the Niobrara were opened in 2010 due to technology advancements, no adjustments were made to the production forecast.

NEW MEXICO OIL AND GAS REVENUE ANALYSIS

DATA

The New Mexico State Land Office provided several datasets (extracted from ONGARD) for use in developing revenue forecast models: (1) well surface location, (2) well bottom hole location, and (3) well-level production data.[8] In addition, lease-level bonus payment data were obtained from the SLO website.[9] Information regarding the variables contained in each dataset, as well as associated definitions, is provided in *Appendix B: Datasets, Variables, and Definitions*.

Well location data (i.e., surface and bottom hole location data) were obtained for all existing wells. To assess the effect of horizontal drilling on oil and gas revenues, horizontal and vertical wells must be identified, which is accomplished using well-level surface and bottom hole location data; if a well's surface and bottom hole are located in the same range, township, section, and unit letter, the well is assumed to be vertical. Alternately, if a well's surface and bottom hole are located in a different range, township, section, and/or unit letter, the well is assumed to be horizontal.

Oil and gas production data is reported at the well and producing zone or pool level. ONGARD contains oil and gas production data for 1994 through the present. To assess whether and how horizontal drilling is affecting oil and natural gas production, well location and production data were merged using both well number and pool identification number.

Bonus payments may serve as a leading indicator of a company's expectations regarding an area's production potential. That is, if a company expects an area to be more productive than other areas, the company will be willing to pay more to acquire access to the area. To assess whether high (low) bonus payments are associated with high (low) production, bonus payment data must be merged with well location and production data. Thus bonus payment data for 1994 through 2011 were obtained from the SLO website.

[8] PUN-level royalty data were also provided by the SLO. Royalty data was used in the *New Mexico Oil and Gas* section of our report, but is not used for revenue forecasting purposes.
[9] http://leasesale.nmstatelands.org/leasesaleresults.aspx

BONUS PAYMENTS

Efforts made by revenue forecasters in other states to develop a model for predicting bonus payments have been unfruitful (see *Bonus Payments*, p. 13). This suggests that a multi-stage spatial modeling process may be required to obtain more accurate forecasts than those achieved through current modeling efforts. We propose the following approach:

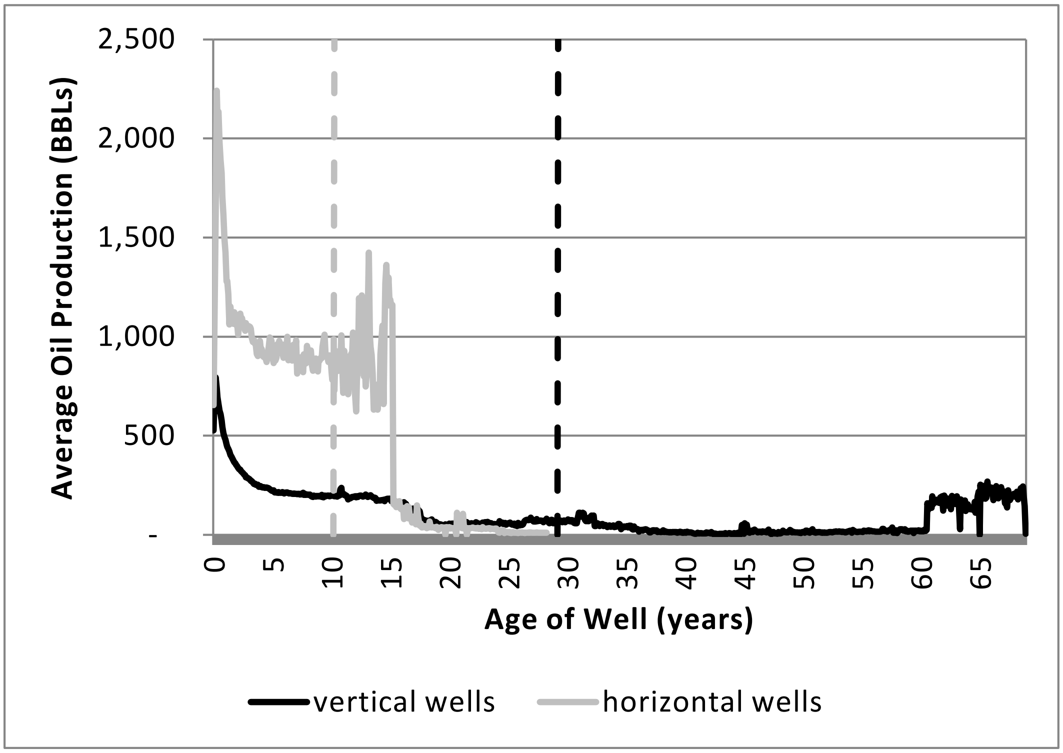
1. Identify what factors/variables determine which tracts SLO will put up for lease. Use this and historical lease auction information to develop a spatial model for predicting which tracts will be auctioned and which tracts will be leased.
2. Use spatial econometrics to predict bonus payments for specific tracts. Explanatory variables might include the following for surrounding tracts: (1) leased or unleased, (2) leased by which company, (3) number of producing and dry wells, (4) well type, (6) production level.

Although conceivable that the proposed approach will yield more accurate bonus payment forecasts than those currently available, the development and construction of such a model is beyond the scope of the present project.

ROYALTIES

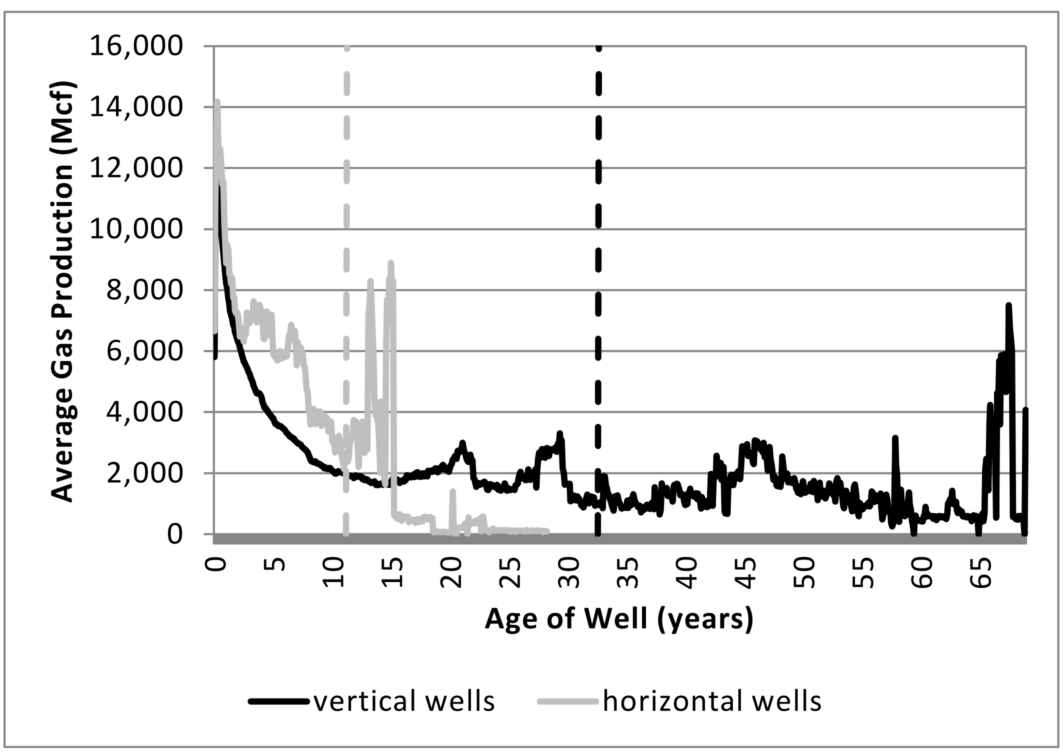
As a first step in assessing whether horizontal drilling technologies are affecting New Mexico's oil and gas royalty revenues, we use monthly production data to compare vertical and horizontal wells' average production as a function of well age (in months). Figure 16 provides a comparison of average oil production time paths for horizontal and vertical wells; Figure 17 compares average natural gas production time paths for horizontal and vertical wells. Production time paths to the right of the dashed vertical lines are likely unreliable due to small sample size; because fewer wells have been in operation for a long period of time, sample size decreases as the age of well increases. The time paths of both oil and natural gas production appear to agree with anecdotal evidence obtained through discussions with analysts in other states – on average, horizontal wells appear to have higher initial production potential but steeper declines. Production increases that occur in older wells may result from the application of secondary or tertiary recovery methods designed to enhance production.

Figure 16. Average oil production time paths for vertical and horizontal wells



Source: Compiled by BBER using ONGARD data.

Figure 17. Average gas production time paths for vertical and horizontal wells

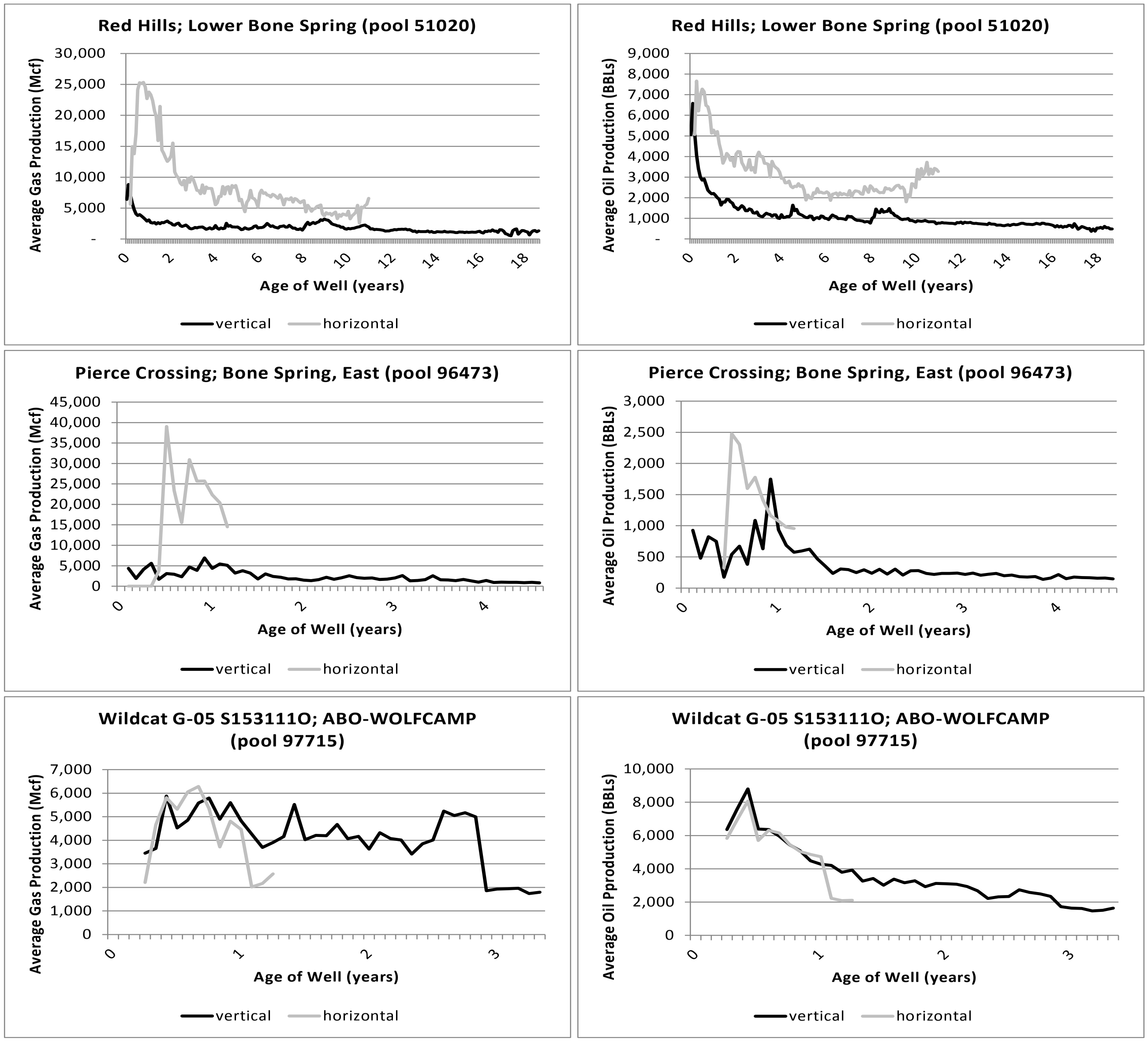


Source: Compiled by BBER using ONGARD data.

Production time paths may differ from one field or pool to another. To provide preliminary insight as to whether this is the case in NM, we compare horizontal and vertical wells' production time paths for various pools.[10] Because horizontal wells still comprise a small portion of NM wells, and due to data issues discussed in *Appendix A: Addressing Data Complexities*, there are a limited number of pools with producing horizontal and vertical wells and for which sufficient and reliable data are available. Figure 18 provides production time paths for a subset of pools. However, results should be considered carefully, as sample sizes are quite small. Sample sizes are largest for pool 51020 (Red Hills; Lower Bone Spring), which for a given well age has between 1 and 25 producing vertical wells and between 1 and 9 producing horizontal wells. (In contrast, other pools depicted in Figure 18 have a maximum of 14 vertical wells and 4 horizontal wells.) Graphs for pool 51020 suggest that horizontal drilling technologies have successfully increased both oil and natural gas production rates; the average production rate from horizontal wells in pool 51020 continues to exceed that of vertical wells even after 10 years of production. Graphs for pool 96473 (Pierce Crossing; Bone Spring, East) also suggest increased production rates as a result of horizontal drilling technology, though horizontal wells accessing pool 96473 have been operational for approximately one year and therefore offer only very preliminary information regarding production time paths. In contrast, pool 97715 (Wildcat G-05 S153111O; ABO-WOLFCAMP) graphs suggest that horizontal and vertical wells have similar production profiles. Thus whether horizontal wells offer a production advantage appears to be field- or pool-specific.

[10] Datasets used in our analysis do not contain field information, but do contain pool identification numbers.

Figure 18. Average vertical and horizontal well production time paths for specific pools



Source: Compiled by BBER using ONGARD data.

SUMMARY AND RECOMMENDATIONS

Horizontal wells are becoming more prevalent in New Mexico; the number of horizontal well completions has been increasing since 2005, whereas the number of vertical well completions has fallen. As a consequence, oil and gas production from horizontal wells has increased exponentially while production from vertical wells has declined. Our analysis suggests that horizontal wells tend to have greater initial production, but production appears to decline more rapidly than that of vertical wells. Preliminary analysis indicates that production characteristics of horizontal and vertical wells differ from one pool to another. BBER's research suggests that improvements to oil and gas revenue forecasts might be achieved by modifying the forecast process to account for changes in technology.

Addressing data availability and quality concerns is a first step to developing better revenue forecasting models. Although ONGARD provides highly detailed and useful information pertaining to well completions and oil and gas production, analyses that employ ONGARD data may be impeded by various data availability and quality issues. Addressing the data availability and quality concerns noted below would increase the usefulness of ONGARD data for revenue forecasting.

1. Hydraulic fracturing is an important technology that is likely affecting New Mexico's oil and gas revenues. Although data regarding the use of fracturing fluids is collected by OCD, the information is not input to ONGARD and is therefore unavailable for modeling and forecasting purposes. We recommend initiating a process of including such information in the ONGARD system so that future analyses can assess the effects of hydraulic fracturing, both in isolation and when used in conjunction with horizontal drilling.
2. As noted in *Appendix A: Addressing Data Complexities*, several data issues remain and should be addressed.

Bonus payments have recently been the source of significant fluctuations in oil and gas revenues. Although none of the methods used by other states to forecast bonus payments would have predicted the recent fluctuations, a spatial econometric model might prove effective in this regard.

The accuracy of royalty forecasts would be improved if more accurate production volumes predictions were developed. Several options exist for additional future analysis of oil and natural gas production levels, including a pool-specific decline curve analysis and an econometric model that accounts for technology (i.e., horizontal drilling and, if possible, hydraulic fracturing).

Pool-specific decline curve analysis might prove useful if oil and natural gas production characteristics are heterogeneous across New Mexico. To assess whether this is the case, the following questions should be considered: (1) Are there a small number of especially productive pools that are responsible for a significant portion of total state production?, (2) Do the time paths of production for the state's most productive pools differ from that of other areas?, and (3) Does the predominant well type in the productive pools differ from that in other areas? If production is heterogeneous, production forecasts may be improved by developing separate models for pools that produce a significant portion of total state production, employ different technologies, or have different production time paths. Preliminary analysis by BBER staff indicates that in 2011 six pools each produced more than

500,000 barrels of oil and jointly produced approximately half of the state's oil.[11] Similarly, five pools each produced more than 10 million Mcf of gas in 2011 and were jointly responsible for more than two thirds of the state's gas production.[12] The predominant technologies and time paths of production of these pools should be compared with those of the state as a whole. If it is found that these productive pools differ significantly from other NM pools, use of a pool-specific decline curve analysis should be considered.

Pool-specific decline curve analysis would entail developing a normalized decline curve – one that models average production by the age of well (in months) – for each major and heterogeneous pool, as well as one for all remaining pools. To predict production levels, normalized decline curves would be applied to all existing wells (and potentially to an estimate of spudded wells) in the relevant pool(s). Developing a normalized decline curve for a given pool would entail lining up all wells' production levels by well age and calculating the average production level for each age of well (in months). However, lack of historical data in ONGARD may preclude such an approach, as production data are not available back to the first month of production for many wells. In fact, ONGARD lacks information regarding well completion dates for many wells, thereby making it impossible to tell the age of many wells.[13] If ONGARD cannot be populated with well completion dates for such wells, then a pool-specific decline curve analysis approach will either need to be modified (perhaps such that normalized decline curves are based solely on wells for which true well completion dates are available, and thus wells for which well age can be determined) or abandoned altogether.

Alternately, a well-level econometric model can be developed and used to forecast future production levels. Potential explanatory variables include well type (horizontal or vertical), age of well, per-acre bonus payment, historical production levels, a productive pool dummy variable, basin (San Juan, Permian, or Raton), and historical rig counts. Although well age will again present difficulties (as true well completion dates are not available for many wells), this is something that can potentially be addressed using econometric techniques.

[11] The six pools are: (1) Vacuum; Grayburg-San Andres (pool 62180), (2) Hobbs; Grayburg-San Andres (pool 31920), (3) Eunice Monument; Grayburg-San Andress (pool 23000), (4) Eunice; BLI-TU-DR, North (pool 22900), (5) Maljamar; Yeso, West (pool 44500), and (6) GJ; 7RVS-QN-GB-Glorieta-Yeso (pool 97558).

[12] The five pools are: (1) Basin Fruitland Coal (Gas) (pool 71629), (2) Blanco-Mesaverde (Prorated Gas) (pool 72319), (3) Bravo Dome Carbon Dioxide Gas 640 (pool 96010), (4) Basin Dakota (Prorated Gas) (pool 71599), and (5) Vacuum; Grayburg-San Andres (pool 62180).

[13] When ONGARD was originally populated with data, well completion dates for existing wells were often entered simply as 1/1/1900.

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APPENDIX A: ADDRESSING DATA COMPLEXITIES

To aid in future replication or revision of the oil and gas revenue projection process, this appendix documents data issues and complexities encountered during the process of conducting the research documented herein. BBER's cleaning and merging of SLO datasets resulted in the identification of various data concerns. Discussions with SLO staff regarding these data concerns resulted in revised data queries and/or further data cleaning. Addressing these data issues has been an iterative process; each revised dataset was re-cleaned and re-merged with other datasets. Because some of the datasets are quite large (the production and royalty datasets contain more than 7 and 5 million observations, respectively), this process was quite time consuming. It was ultimately decided that no further data revisions would be made. Notes regarding unaddressed data issues are included in the final section of this appendix (*Data Concerns to be Addressed in Future*). These issues should be addressed as part of any future analysis.

WELL LOCATION (SURFACE AND BOTTOME HOLE) DATASETS

Care must be taken when pulling surface and bottom hole location data from the ONGARD system. The initial set of surface location data received from SLO contained numerous instances of wells listed multiple times, with multiple listings representing different surface owners. SLO subsequently provided revised surface location data that contains only current ownership data and therefore only current records. A similar issue was noted in the bottom hole data received from SLO. Duplicate listings were identified as those that met one of two conditions: (a) identical well number, bottom hole location, and pool identification number, but different production unit numbers, or (b) identical well number, bottom hole location, pool identification number, and production unit number, but different subsurface owners. Although the SLO subsequently provided a revised bottom hole location data file that reduced the incidence of such issues, more than 2,900 of the 30,525 observations in the revised bottom hole location file still meet one of these conditions. Because SLO staff are unsure of the reason or explanation for these anomalies, it is unclear how to address this data irregularity; such observations were therefore omitted from our analysis.

BBER identified 828 wells that cannot be categorized as vertical or horizontal due to missing data; some wells have surface location data but no bottom hole location data (794 wells), while other wells have bottom hole location data but no surface location data (34 wells). Wells with incomplete location information are maintained in the dataset for some portions of the analysis, but omitted for others.

COMBINING PRODUCTION DATA AND WELL LOCATION DATA

Well numbers and pool identification numbers are used to combine (merge) well location data with production data, resulting in a dataset containing more than 7 million observations. BBER identified almost 185,000 records of production data (associated with 823 wells) that are missing well location data, as well as approximately 1,300 records with well location data but no production data. While it seems reasonable to have well location records with no production data (as this reflects the fact that some wells are dry), it is unclear why there exists production data with no associated well location data. Observations with missing production or well location data are omitted from our analysis of well production characteristics.

A well's age at the time of production is calculated as the difference between the date of production (contained in the production dataset) and the date of well completion (contained in the bottom hole location dataset). However, comparing well completion dates with drilling permit dates suggests that well completion dates may frequently be inaccurate; 71 percent of wells have a well completion date identical to the date on which the drilling permit was approved, and an additional 3 percent have a well completion date that precedes the drilling permit date. Because an inaccurate well completion date will yield an inaccurate well age at time of production, we opt to exclude these 75 percent of wells from the data used for analyzing production time paths. As a consequence the set of wells is reduced from 29,920 wells to 7,911 wells. Location data for these 7,911 wells are merged with the production data, and additional observations are omitted due to (a) missing well completion date, (b) missing production date, (c) a production date that precedes the well completion date, (d) missing bottom hole location data, or (e) missing surface location data. Omissions reduce the size of the dataset to approximately 1.4 million observations (roughly 20 percent of the observations contained in the full merged well location and production dataset).

ROYALTY DATA

Although observations in the royalty data set have a product code (PRD_CDE), some product codes do not relate to oil or gas. We use only data with a product code equal to 1, 2, 3, 4, 5, 7, 14, 16, or 17 and thus retain only observations associated with oil or gas production.[14] Additionally, several errors and anomalies were discovered in the royalty data set: (a) illogical report or sales years, (b) a report date that precedes the sales date, (c) no lease prefix, and (d) no PUN value. These issues require omission of additional observations from our analysis.

Illogical date values include a sales year value that occur in the future (2020) and negative report year values. Only data with a report year between 1994 and 2011 and a sales year of no later than 2011 are used. The royalty dataset also contains 3,157 observations for which the month and year in which the OGR-2 form was filed (RPT_MTH and RPT_YR) precede the month and year of sale (SALES_MTH and SALES_YR). Royalties associated with these observations total $2.5 million (0.06 percent of total royalties). SLO staff examined a subset of such observations and found that although the RPT_YR and RPT_MTH variables accurately reflected what had been recorded on the OGR-2 form, the date values provided on the form were incorrect. Because we use RPT_YR and RPT_MTH to assign royalty revenues to the fiscal year in which the royalties were paid, and because it is not possible to determine the correct RPT_YR and RPT_MTH values, BBER omitted such observations from our analysis. Although at some level this may appear to raise concerns regarding the accuracy of the RPT_YR and RPT_MTH values in the dataset as a whole, most companies (especially large companies that generate significant royalty revenues for the state) file computer-generated reports that should not contain such errors.

Nearly 1,500 observations have no lease prefix (LEASE_PRFX_IDN). Because the LEASE_PRFX_IDN variable is used to determine the royalty rate for each lease (see Table 2), we are unable to determine the appropriate royalty rate for these observations. However, because royalty rates are not necessary for the development of a revenue forecasting model, it is not necessary to omit these observations from the dataset. The royalty dataset also contains 794 observations with no PUN value and 363 observations for which the PUN value is zero.

[14] Product code definitions: 1= oil (BBLs), 2=oil condensate (BBLs), 3=gas, processed (residue) gas (Mcf/BTU), 4=gas (wet) (Mcf/BTU), 5 = oil, other liquid hydrocarbons (BBLs), 7=gas plants products (NGL gallons) (W/H (Mcf) – Res (Mcf), 14 = oil, lost (BBLs), 16 = gas, lost, flared, or vented (Mcf), and 17 = CO_2, carbon dioxide gas (Mcf).

Table 2. Lease prefixes and associated royalty rates

LEASE_PRFX_IDN	Royalty Rate
V	1/6
V0	1/6
VA	1/8
VB	3/16
VC	1/5
VZ	1/6
all other	1/8

Source: NM State Land Office.

To assess royalties on a spatial scale, production unit numbers are used to combine the royalty dataset with well location information. We therefore omit observations with either a missing PUN value or a PUN value of zero. Given that royalty data is reported at the PUN level and we are merging the royalty data with well-level location data, royalty data may be duplicated and double counted when there are multiple wells associated with a given PUN. Surprisingly, this does not appear to be much of an issue; whereas the royalty dataset contains total royalties of $4,428,168,960, the merged royalty and well location dataset contains total royalties of $4,428,410,740 (an increase of less than $242,000). When analyzed by fiscal year, the average difference in royalties is approximately $13,000 and the maximum difference is approximately $135,000 (Table 3). Royalties are only double counted when a specific PUN and lease combination is associated with more than one well, and this does not appear to occur on a frequent basis. For the FY 2011 data, BBER found only one case in which multiple wells were associated with a given PUN and lease for which royalties had been reported.[15] Thus although the merge inevitably will result in some double counting of royalties, the incidence is limited and therefore determined to be non-problematic for our purposes.

[15] Interested parties should see royalty return ID (OGR1_RET_IDN) = 79702, page 3, line 12, PUN 1209285, and lease L0-5852, which has the following wells associated with it: 21-20445, 21-20504, 21-20505, 21-20507, 21-20508, 21-20510, 21-20514, 21-20515, 21-5047, and 21-5091.

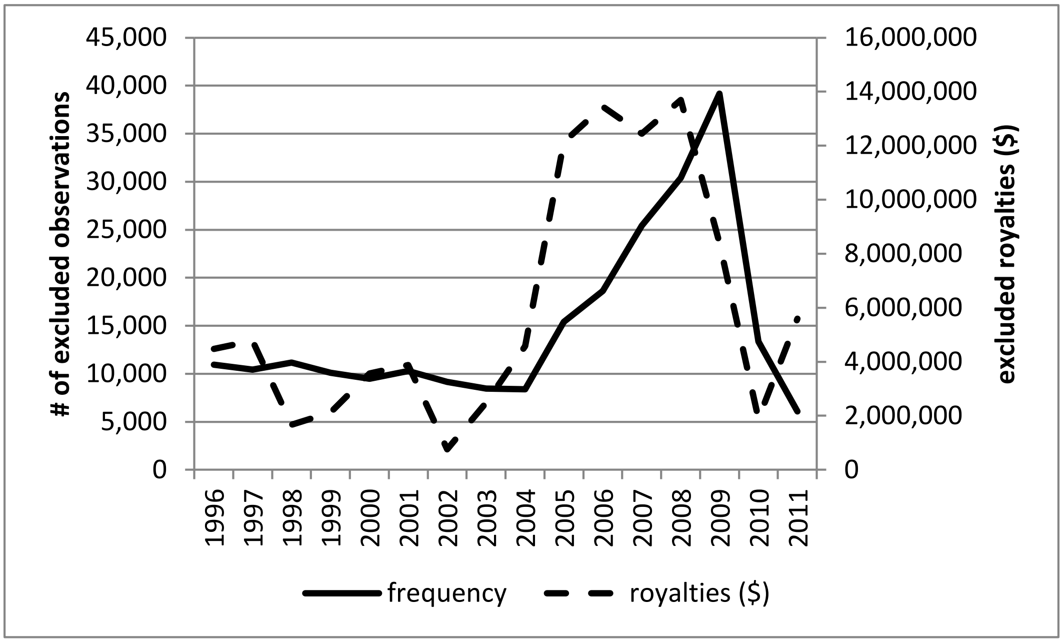
Table 3. Comparison of FY royalties: Royalty data vs. merged well location and royalty data

FY	Royalties ($)		
	Royalty Dataset	Merged Well Location & Royalty Dataset	Difference
1995	2,279,191	2,278,837	-354
1996	99,836,469	99,842,210	5,741
1997	134,568,836	134,703,520	134,684
1998	119,004,304	118,973,752	-30,552
1999	94,811,009	94,834,913	23,904
2000	153,472,237	153,472,237	0
2001	276,282,721	276,283,340	619
2002	178,046,063	178,100,899	54,836
2003	241,981,058	241,981,058	0
2004	243,584,269	243,584,549	280
2005	321,087,298	321,094,543	7,245
2006	409,553,265	409,563,741	10,476
2007	378,711,438	378,738,464	27,026
2008	430,748,969	430,748,969	0
2009	462,251,793	462,256,184	4,391
2010	319,063,368	319,063,368	0
2011	388,191,943	388,195,246	3,303
2012	174,694,729	174,694,910	181
Total	4,428,168,960	4,428,410,740	241,780
Average	246,009,387	246,022,819	13,432
Maximum	462,251,793	462,256,184	134,684

Source: Compiled by BBER using ONGARD data.

The merged well location and royalty dataset contains over 1,900 observations with well location data but no royalty data and more than 240,000 observations with royalty data but no well location data. These observations were deleted for purposes of assessing the spatial distribution of royalties, thereby omitting $101.4 million (2 percent) of royalties. Omitted observations and royalties are charted by FY in Figure 19.

Figure 19. Observations and royalties excluded from analysis due to lack of well location information



Source: Compiled by BBER using ONGARD data.

DATA CONCERNS TO BE ADDRESSED IN FUTURE

Efforts should be made to address incomplete well location data (i.e., missing surface and bottom hole location data) and ensure that all wells have both surface and bottom hole location data available in ONGARD. The availability of such data is necessary to assess how horizontal drilling is affecting productivity and revenues.

The bottom hole location dataset contains numerous observations with the same well number, bottom hole location, and POOL_IDN but different PUNs. The SLO's initial opinion was that such observations appeared to be in error (and should therefore be omitted from our analysis). However, SLO later indicated that this is not uncommon and can occur when a well is sold. Observations that meet these criteria should therefore be included in future analyses rather than being omitted. SLO staff should determine why the bottom hole location dataset also contains observations with identical well number, bottom hole location, POOL_IDN, and PUN, but different subsurface owners and assess how best to address this data irregularity.

BBER identified nearly 185,000 observations with production data but no associated well location data. The reason for these occurrences is unclear and should be addressed in future work.

Comparing production time paths for horizontal and vertical wells is crucial to ascertaining how horizontal drilling is affecting state revenues. Production time paths assess production as a function of well age, where a well's age is calculated as the difference between the date of production and the date of well completion. Yet as noted previously, a large portion (74 percent) of observations must be omitted from the analysis due to well completion dates of questionable accuracy, as they either precede or are identical to the well's drilling permit date. Twenty seven percent of such observations have drilling permit and well completion dates of 1994 and later (i.e., after the inception of ONGARD), which indicates that this type of error is not limited to historical data but has also occurred when ONGARD is updated with information regarding new wells.[16] Further data anomalies (production dates that precede the well completion date) and missing data (missing well completion dates and/or production dates) require the omission of additional observations from this analysis. The size of the merged well location/production dataset available for assessing production time paths is reduced by 80 percent as a result of these data problems; addressing these concerns will yield more accurate assessments of differences in vertical and horizontal wells' production time paths.

[16] The remainder of such observations have drilling permit and well completion dates that precede ONGARD – some have drilling permit and well completion dates of 1/1/1900 (the default date used when originally populating ONGARD with data), while others have dates that fall between 1900 and 1993 (the year before ONGARD was launched).

APPENDIX B: DATASETS, VARIABLES, AND DEFINITIONS

This appendix provides information regarding the variable names and definitions for each dataset provided by the SLO. Well surface location data (Table 4) identify the surface location of each well (i.e., the range, township, section, and unit letter associated with the well's surface location); whether the associated land is currently owned by a state, federal, Indian, or private entity; and the date on which the application to drill the well was approved. Included in this dataset are all existing wells, regardless of whether they are currently producing.

Table 4. Well surface location data: Variables and definitions

Variable	Definition
API_CNTY_CDE	county code
API_WELL_IDN	well identification number
EFF_DTE	application to drill approval date
SDIV_RNG_IDN	surface range
SDIV_SECT_NUM	surface section
SDIV_TWP_IDN	surface township
SDIV_UNLT_IDN	surface unit letter identification number
SRFC_OWN_CDE	current surface ownership code

Bottom hole location data (Table 5) identify the location of the bottom hole of each well (i.e., the range, township, section, and unit letter associated with the bottom hole); whether the subsurface associated with the bottom hole is currently owned by a state, federal, Indian, or private entity; the identification number of the pool produced by the bottom hole; the PUN; and the date on which the bottom hole was completed. Included in this dataset are all existing wells, regardless of whether they are currently producing.

Table 5. Well bottom hole location data: Variables and definitions

Variable	Definition
API_CNTY_CDE	county code
API_WELL_IDN	well identification number
EFF_DTE	well completion date
POOL_IDN	pool identification number
PUN	production unit number
SDIV_RNG_IDN	bottom hole range
SDIV_SECT_NUM	bottom hole section
SDIV_TWP_IDN	bottom hole township
SDIV_UNLT_IDN	bottom hole unit letter identification number
SSRFC_OWN_CDE	current subsurface ownership code

Well-level production data (Table 6) list the production year and month for each well, the production pool(s), the product (oil or gas) produced, and the volume produced. Included in the production dataset are all currently available ONGARD production data, which spans from January 1994 through September 2011.

Table 6. Production data: Variables and definitions

Variable	Definition
API_CNTY_CDE	county code
API_WELL_IDN	well identification number
POOL_IDN	pool identification number
PRD_KND_CDE	product code (O=oil, G=gas)
PROD_AMT	product volume (oil: barrels, gas: Mcf)
PRODN_MTH	month in which production occurred
PRODN_YR	year in which production occurred

Royalties are reported at the PUN and lease level. The royalty data (Table 7) include information pertaining to the PUN and lease number; the month and year of sale; the volume of oil, gas, or natural gas liquids sold; the average BTUs (gas only); allowable deduction amounts (transportation, processing, and marketing); gross proceeds; the month and year in which associated royalties were reported; the relevant OGR-2 form page and line numbers; an "arms length" dummy variable indicating whether a related transaction is occurring (such as a producer processing their gas at their own plant and thereby taking a processing deduction); and royalties paid. ONGARD royalty data are currently available for June 1994 through October 2011.

Table 7. Royalty data: Variables and definitions

Variable	Definition
ALLOW_DEDN_MKT	marketing deduction
ALLOW_DEDN_PROC	processing deduction
ALLOW_DEDN_TRNSP	transportation deduction
ARM_LEN_IND	arms length transaction dummy variable
AVE_BTU_GAS	average BTUs (for gas)
GRS_PROCD	gross proceeds
LEASE_PRFX_IDN	lease prefix identification number
LEASE_SEQ_NUM	lease sequence number
LN_NBR	OGR-2 line number
OGR1_RET_IDN	identification number assigned to royalty return
OGRID_CDE	oil and gas reporting identification number (i.e., company number)
PG_NBR	OGR-2 page number
PRD_CDE	product code (O=oil, G=gas)
PUN	product unit number
ROY_RPT_PD_AMT	royalties reported as paid
RPT_DD	day on which OGR-s form was filed
RPT_MTH	month in which OGR-2 form was filed
RPT_YR	year in which OGR-2 form was filed
SALES_MTH	month in which sale occurred
SALES_YR	year in which sale occurred
VOL_GAS_MCF	volume of gas (Mcf)
VOL_NGLS_GALN	volume of natural gas liquids (gallons)
VOL_OIL_BBLS	volume of oil (barrels)

Bonus payment data (Table 8) include the lease number, lease location (i.e., the range, township, section, and description of the lease), tract number, the month and year of the lease, the size of the lease (acres), the name of each company that bid on a given tract, the amount of the winning bid and the resulting price per acre, and the county in which the tract is located. We omit from the dataset all information associated with non-winning bids.

Table 8. Bonus payment data: Variables and definitions

Variable	Definition
ACRES	acres leased
BID AMOUNTS	lease (bonus) payment ($)
BIDDER	leasing company
COUNTY	county in which tract is located
DESCRIPTION	tract description
LEASE #	lease number
Mth/Yr	month and year of lease sale
PRICE/ ACR	bid amount per acre ($/acre)
RGE	range
SEC	section
TRACT #	tract number
TWP	township