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UNNECESSARY AND UNAFFORDABLE: THE CASE FOR CURBING OKLAHOMA'S OIL AND GAS TAX BREAKS

by David Blatt, Ph.D.

Oklahoma should eliminate tax breaks for the oil and gas industry that are no longer needed and are squeezing out resources for schools, roads, public safety, and other keys to long-term economic growth. Policymakers created the tax exemptions to encourage what were at the time novel and risky methods of drilling, but these techniques now are standard practice, making the exemptions not only unnecessary but counterproductive.

The oil and gas industry is unquestionably vital to Oklahoma's economy. The energy sector accounts for nearly 9.5 percent of Oklahoma's gross state product and employs 4.6 percent of the state's nonfarm labor force.¹ Although the state economy has diversified to some extent since the oil bust of the 1980s, our economic prosperity remains closely tied to the fortunes of the energy industry.

Revenue from oil and gas production is also a vital component of the state's tax system. It provides the funding to educate our children, protect our communities, maintain our transportation grid, and assist those in need. Oklahoma assesses a 7 percent gross production tax on oil and gas extraction, except when prices fall below a certain floor. However, several production methods, including horizontal drilling and deep-well drilling, benefit from tax rebates and credits that lower the tax rate to just 1 percent for horizontally-drilled wells and 4 percent for deep wells.

These tax breaks were enacted when these drilling techniques were new and relatively risky. Today they are standard industry practice with far fewer risks. As a result, oil and gas production has shifted increasingly towards horizontal and deep well drilling, and the cost of these tax breaks has skyrocketed.

The state paid out or accrued \$645 million in tax rebates and credits to the industry over the latest 3-year period (FY 2010 – FY 2012). Most of the credits - \$537 million – went to producers of horizontal wells. Without legislative action to change course, the cost of these credits will continue to grow exponentially in coming years, reducing the resources available to fund core public services.

An examination of gross production taxes and exemptions finds that tax breaks are neither a necessary nor an efficient way to encourage oil and gas production and that curtailing these tax breaks is unlikely to harm Oklahoma's energy industry or economy. In fact, doing so would help the economy by making more revenue available for sorely-needed investments in education, infrastructure, health care and other building blocks of economic prosperity. To help create jobs and build a strong economy, Oklahoma should eliminate or curtail its tax preferences for horizontal and deep well drilling in favor of more uniform tax treatment that will continue both to allow energy producers to operate profitably and ensure that the state can support the services that enable our families, communities and businesses to prosper.



I. TAXING OIL AND GAS IN OKLAHOMA

Tax Rate

Oklahoma assesses a gross production tax, also called a severance tax, on the extraction of oil, natural gas, and other minerals. The tax is assessed as a percentage of gross market value based on the average monthly price for each product as determined by the Oklahoma Tax Commission. For oil and natural gas, the basic tax rate is 7 percent; however, the tax rate is lower when prices fall below specified minimums. The tax rate is 4 percent on oil when its price is between \$14 and \$17 per barrel and when gas is between \$1.75 and \$2.10 per million cubic feet (MCF). The tax drops to 1 percent when oil is below \$14 per barrel and gas is below \$1.75 per MCF.

Natural Gas (price per MCF)	Oil (price per barrel)	Tax Rate
>\$2.10	>\$17	7%
\$1.75 - \$2.10	\$14 - \$17	4%
<\$1.75	<\$14	1%

How Gross Production Taxes are Used

Gross production tax revenues are distributed between various state and local funds. The allocation is different for natural gas and oil, and also is different depending on the tax rate (see above). If the tax rate is 7 percent, natural gas revenues are apportioned as follows:

- 85.72 percent to the General Revenue fund;
- 7.14 percent to county roads; and
- 7.14 percent to school districts.

Oil revenues are divided in a more complicated fashion:

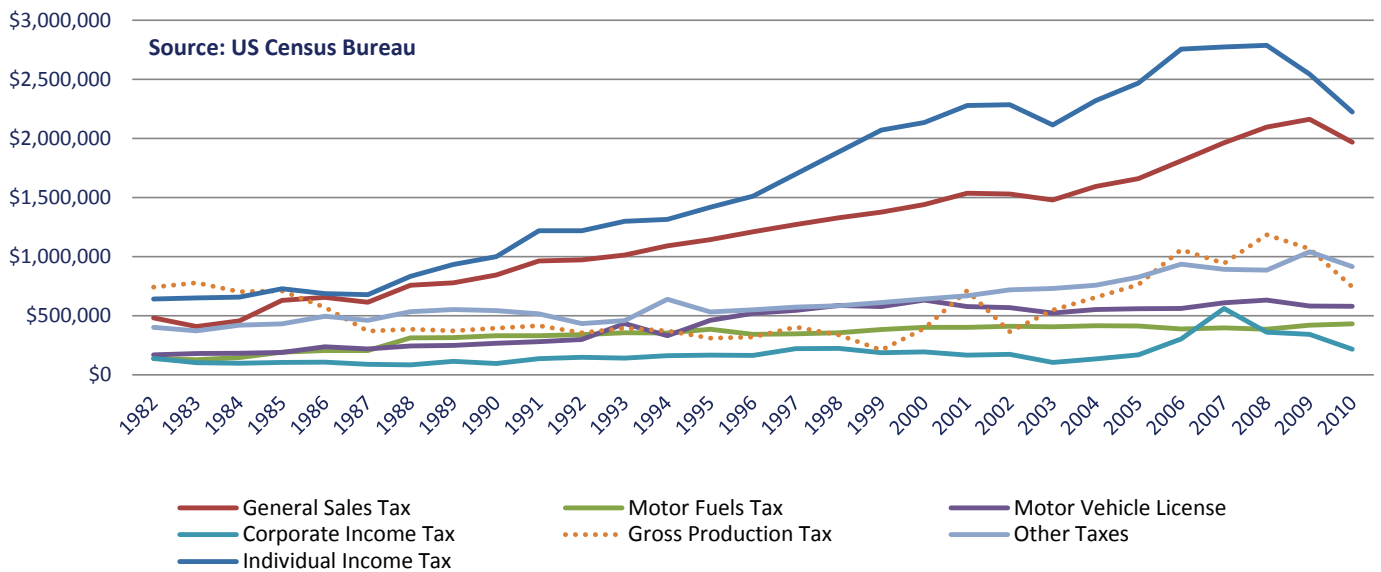
- 77.16 percent divided between three education funds;
- 7.14 percent to county roads;
- 7.14 percent to school districts;
- 3.745 percent dedicated to County Bridge and Road Improvement Fund;
- 4.80 percent divided between various small funds.

Revenues allocated to the three education funds and the various small funds are capped at a total of \$150 million; revenues above that amount are deposited in the General Revenue Fund. Both oil and gas revenues are subject to different distribution formulas when the tax rate is 4 percent or 1 percent; however, county roads and school districts are always ensured gross production tax revenues whatever the tax rate.

Gross Production Tax Revenues

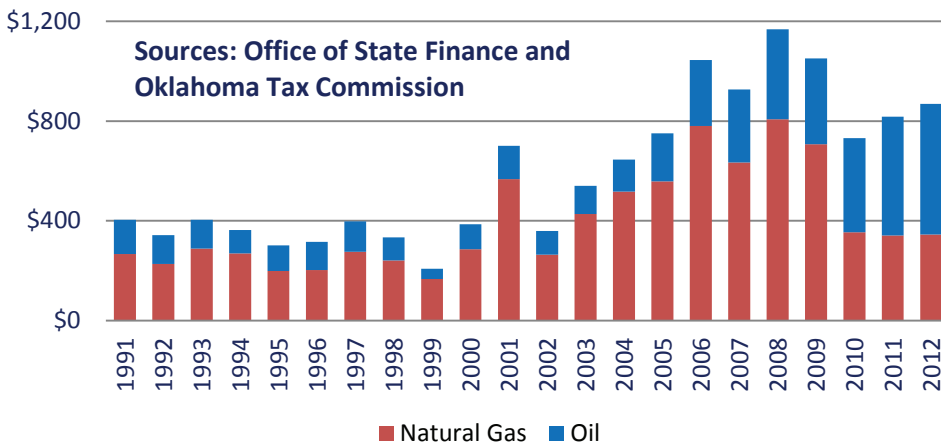
Gross production tax (GPT) collections have fluctuated greatly over the past decades in conjunction with energy prices. Gross production taxes accounted for 30 percent of state tax revenues in 1982 and were the largest single source of state revenue until 1984, when they were overtaken by personal income taxes. GPT collections remained in the range of \$300 - \$400 million annually from FY 1987 to FY 1998 before rising for most of the 2000s.

Figure 1
State Tax Collections by Major Tax Type, Oklahoma, 1982-2010
 (in \$ Thousands)



Total collections from gas and oil reached an historic high of nearly \$1.2 billion in FY 2008 but fell in FY 2010 before recovering slightly in FY 2011 and 2012. Between FY 1991, when oil and gas collections were first reported separately, and FY 2009, natural gas revenues exceeded oil revenues every year. With natural gas prices low and oil prices high, this situation has now reversed in each of the past three years. In FY 2012, oil revenues brought in \$523.9 million compared to natural gas revenues of \$345.7 million.

Figure 2
Oklahoma Annual Natural Gas and Oil Tax Collections, FY '91 - FY '12 (in \$ millions)



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Gross production taxes represented 10.7 percent of total state taxes in FY 2011, ranking as the third leading source of state tax revenues behind the personal income tax (\$2.4 billion, or 32 percent) and the sales tax (\$2.0 billion, or 26 percent).

II. OIL AND GAS TAX BREAKS

Beginning in the early 1990s, the Legislature enacted a set of tax breaks that partly or fully exempted certain types of oil and gas production from the gross production tax. The exemptions were intended to encourage forms of production that involved greater risks and higher costs for producers and that used innovative and expensive technologies.

Oklahoma law provides tax exemptions for seven types of oil and gas production: 1) enhanced recovery projects (economically at-risk wells); 2) horizontally drilled wells; 3) inactive wells (reestablished production); 4) production enhancement projects; 5) deep well drilling; 6) new discovery wells; and 7) three-dimensional seismic shoots.² These exemptions are all subject to sunset clauses. Currently, the exemptions for horizontal and deep well drilling are due to expire July 1, 2015, while the other exemptions are due to expire July 1, 2014.

To qualify for an exemption, the Oklahoma Corporation Commission must certify eligibility before the start of production. If a well qualifies under more than one exemption category (for example, a horizontally drilled well deeper than 15,000 feet), the producer selects which exemption to apply for.

The exemptions, in most cases, are equal to 6/7ths of the gross production tax, which means that the producer pays a 1 percent tax. As of July 1, 2011, production from deep wells below 15,000 feet is taxed at 4 percent. Enhanced recovery projects are fully exempt from the gross production tax.

However, these drilling exemptions may be limited in three ways:

- 1.** *By price* - most drilling exemptions are suspended when the average annual index price of oil or gas is above \$5 per MCF of gas or \$30 per barrel of oil. The only exemptions not subject to a price trigger are those for horizontally drilled wells, deep wells below 15,000 feet spudded after July 1, 2005, and enhanced recovery projects. Legislation passed in 2010 (HB 2432) allows the price at which exemptions are granted to rise annually based on the Consumer Price Index.
- 2.** *By duration* – all oil and gas tax exemptions can be claimed only for a set length of time following a project's initiation or completion. For most drilling, exemptions can be claimed for 28 months from the date of first sales. The exceptions are for:
 - ◇ Horizontal wells—Until July 1, 2011, the exemption was for 48 months or until project costs are recovered ('project payback'). HB 2432 removed the project payback limit for production after July 1, 2011.
 - ◇ Deep wells - the exemption is for 48 months from the date of first sales for wells between 15,000 and 17,499 feet and 60 months for wells 17,500 feet and deeper.
 - ◇ Enhanced recovery projects—the exemption is for five years or the end of the secondary recovery project.
- 3.** *By amount* – For deep wells below 15,000 feet, the total amount of exemptions claimed was capped at \$25 million per fiscal year as of FY 2009. HB 2432 removed the cap and instead set the tax on all deep wells below 15,000 feet at 4 percent effective July 1, 2011. No other exemptions are capped as to their total amount.

Overall, the most generous exemptions are for enhanced recovery projects and for horizontally drilled wells, which are taxed for 48 months at 1 percent regardless of the price of oil and gas and even if all project costs have been recovered. Deep wells drilled below 15,000 feet are taxed at 4 percent for 48 months from the date of first sales regardless of the price of oil and gas

Until July 1, 2011, all oil and gas exemptions were paid out as rebates on claims filed after the end of the fiscal year in which production occurred. HB 2432 altered the way in which exemptions are claimed. Under the bill, negotiated by legislative leaders and the energy industry in the midst of severe budget shortfalls, rebates for horizontal and deep well drilling accrued during FY 2010 and FY2011 were deferred for 24 months. The rebates will be paid out over 36 months beginning in July 2012 (FY 2013); the state will be charged 9 percent interest on any late payments. Beginning July 1, 2011 (FY 2012), exemptions for horizontal and deep well drilling are claimed as front-end credits on qualifying wells rather than as rebates.

Data supplied by the Oklahoma Tax Commission shows the amount of gross production tax rebates claimed for each kind of production from FY 2004 – FY 2012 (Table 2). Under the tax rebate system, producers can claim rebates at the beginning of each fiscal year for production during the prior 18 months. For example, rebates paid out in FY 2004 were for production between January 1, 2002 and June 30, 2003; rebates paid out in FY 2010 were for production between January 1, 2008 and June 30, 2009. In some cases, when rebate claims are challenged, payments can go back beyond eighteen months.

TABLE 2: GROSS PRODUCTION TAX REBATES PAID, FY '04 - FY '11

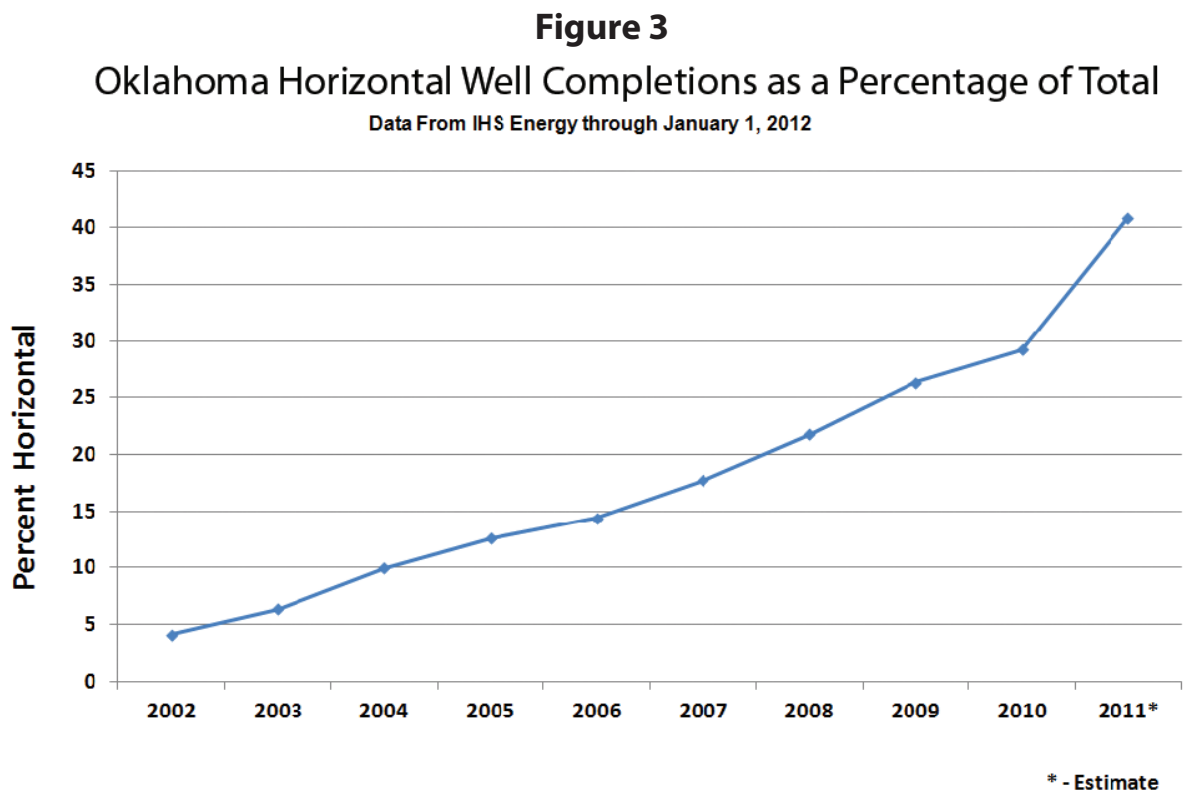
Claim PERIOD	Reestablished Production	Production Enhancement	New Discovery	3-D Seismic	Economically At-Risk	Deep Wells*	Horizontally Drilled Wells*	TOTAL REBATES
FY 2012*	\$394,133	\$6,094,458	\$10,507	\$15,716,252	\$6,649,331	\$5,868,811	\$2,768,334	\$37,501,826
FY 2011*	\$50,017	\$3,245,531	\$41,817	\$1,138,409	\$5,828,372	\$20,642,672	\$108,206,670	\$139,153,488
FY 2010	\$127,000	\$2,388,000	\$6,000	\$76,000	\$1,421,000	\$25,376,000	\$83,383,000	\$112,777,000
FY 2009**								\$65,300,000
FY 2008	\$335,220	\$186,210	\$35,925	\$111,693	\$733,034	\$20,000,000	\$35,601,260	\$57,003,342
FY 2007	\$2,313,095	\$1,979,933	\$271,289	\$4,093,132	\$218,935	\$12,883,845	\$25,834,322	\$47,594,551
FY 2006	\$8,161,496	\$13,066,852	\$2,590,112	\$17,242,747	\$84,575	\$46,759,454	\$17,813,629	\$105,718,865
FY 2005	\$2,825,352	\$11,399,758	\$1,546,791	\$9,656,266	\$53,646	\$59,555,912	\$4,372,142	\$89,409,867
FY 2004	\$2,584,677	\$6,808,032	\$965,791	\$2,651,966	\$356,234	\$23,847,903	\$2,366,979	\$39,581,582
Total								
FY '04 - FY '12	\$16,790,990	\$45,168,774	\$5,468,232	\$50,686,465	\$15,345,127	\$214,934,597	\$280,346,336	\$694,040,521

** : For horizontal wells and deep wells, rebates paid in FY '11 and FY '12 were all for production prior to FY '10
 *: OTC unable to break down rebates by type of production for FY '09
 Source: Oklahoma Tax Commission

As can be seen from Table 2, the cost of most of the gross production tax exemptions has been relatively modest. In 2008 and 2010, for example, the state paid out less than \$5 million in rebates for five of the seven favored forms of drilling (reestablished production, production enhancement, new discovery, 3-D Seismic, and economically at-risk wells) combined. The fact that these rebates cannot be claimed when prices are above specified levels (\$30.00 per barrel of oil or \$5.000 per MCF of gas) has especially curbed the cost of the exemptions. In 2011 and 2012, as natural gas prices fell below the price cap, the amount paid out in rebates for production enhancement wells, economically at-risk wells, and 3-D Seismic shoots increased, reaching \$28.5 million in 2012.

The situation is very different – and considerably more complicated – for deep well drilling and horizontal drilling. As deep well drilling became more prevalent in Oklahoma in the late 1990s and early 2000s, the cost of the tax break rose sharply, reaching \$59.6 million in FY 2005. The Legislature approved legislation in 2005 that created an annual cap on rebates for production from deep wells below 15,000 feet. No rebates were to be paid for FY 2006, and then rebates were capped at \$17 million for FY 2007, \$20 million for FY 2008, and \$25 million for FY 2009 and subsequent years. The \$25 million annual cap remained in effect through FY 2010. When total claims exceeded the cap, the Oklahoma Tax Commission would allocate the rebates proportionately among producers.

In 2005, when deep well drilling exemptions were placed under their annual cap, horizontal drilling was relatively rare in Oklahoma. Very quickly, however, horizontal production began to grow. By 2010, horizontal well completions had risen to almost 30 percent of all wells, up from less than 5 percent in 2002, and this is projected to rise to over 40 percent in 2011³ (Figure 3).



From: Dan T. Boyd, "Oklahoma 2011 Drilling Highlights", Shale Shaker, The Journal of Oklahoma City Geological Society, March – April 2012, p. 383

As horizontal drilling, which benefits from the most preferential tax treatment, has grown, the cost of this exemption has exploded. Rebates claimed on horizontal drilling jumped to \$35 million in FY 2008 and to \$83 million in FY 2010 from just \$2 million in FY 2004. The FY 2010 rebate for horizontal drilling alone was more than the total amount of rebates paid out for all forms of production in any of the three previous years.

Legislation approved in 2010 changed the way that horizontal and deep well drilling exemptions are paid out. HB 2432 deferred rebates accrued on production from horizontal and deep wells that occurred during 2010 and 2011. Rebates for that 24-month period will be paid out over 36 months beginning July 1, 2012 (FY 2013). As of July 1, 2011 (FY 2012), producers of horizontal and deep wells pay tax at a reduced rate upfront (1 percent for horizontal, 4 percent for deep wells under 15,000 feet) rather than claim credits.

All of this makes annual comparisons of the exemption's costs extremely difficult. To get a complete picture for horizontal and deep well drills during 2010, 2011 and 2012 requires combining the following:

- Rebates paid out for production prior to 2010: horizontal - \$194.4 million; deep well - \$51.9 million (see Table 2)
- Rebates accrued for production in 2010 and 2011 to be paid out beginning in 2013: horizontal - \$245 million; deep well - \$50 million⁴
- Benefit of 2012 production taxed at lower rate: horizontal – \$98.5 million; deep well - \$5.3 million⁵

In total, the state has paid out or accrued some \$645 million in tax breaks for horizontal and deep wells in the past three years (which includes rebates paid out for earlier production). Horizontal drilling tax breaks alone have totaled \$537 million.

The cost of horizontal drilling tax breaks now exceeds \$100 million a year. But this may only be the tip of the iceberg if horizontal production continues to grow as anticipated. In the early 2000s, horizontal drilling techniques were being used in a limited geological area by very few producers. Over the past decade, horizontal drilling has spread rapidly into new reservoirs across broad swaths of Oklahoma. "There is now an ever-lengthening list of reservoirs that lend themselves to horizontal drilling and completion techniques", according to the most recent annual survey of drilling in Oklahoma published by the Oklahoma City Geological Society.⁶ For the past two years, every one of the 15 oil and gas wells identified in the annual drilling survey as the most significant wells in Oklahoma is a horizontal well.⁷ As of July 2012, 50 of 53 gas rigs operating in Oklahoma and 136 of 148 oil rigs were engaged in horizontal drilling.⁸

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Unlike conventional wells, which can produce steadily over an extended period, horizontally drilled wells have steep decline curves, meaning that there is an initially large output of oil and gas that declines quickly. A study of the Bakken shale in the Western states found that after three years, average daily production is only 21 percent of peak production in the second month.⁹ With horizontal wells enjoying a 1 percent tax rate for 48 months after initial production, this means that most production from most wells drilled in Oklahoma will go essentially untaxed.

The potential cost to state revenues from horizontal and deep well drilling exemptions will depend on oil and gas prices and production levels. But if total production remains steady at current levels, and horizontal drilling reaches 50 percent of total production, the state could soon be giving up \$400 million annually in horizontal drilling credits.¹⁰ If prices rise and horizontal production becomes even more dominant, the dollar loss to the state would be even greater.

III. WHY EXEMPTIONS SHOULD BE CURBED

Leaving aside the hot debate over the environmental impact of horizontal and deep well drilling, there is little doubt that the boom in new drilling techniques has provided substantial benefits for Oklahoma's energy industry and for the state economy. However, this calls into question whether the state's preferential tax treatment for horizontal and deep well drilling is still justifiable, especially now that these techniques have become commonplace and account for a large and rising share of Oklahoma's oil and gas production.

Tax breaks could be defended if they played a significant role in the decision by producers to drill, were needed for drilling to be profitable, or were needed to promote production in Oklahoma rather than elsewhere. But Oklahoma's oil and gas tax breaks fail all of these tests.

State oil and gas tax preferences do not significantly influence the decision to drill

Experts agree that a tax preference is justified if it spurs economic activity that otherwise would not occur. "Incentive programs are to be targeted to firms where the program will make a difference," states Oklahoma's Incentives Review Committee in its list of guiding principles for evaluating tax subsidies.¹¹

A 2008 non-scientific survey of Oklahoma oil and gas companies conducted by Oklahoma City University business professor Steven C. Agee found that 83 percent had claimed gross production tax incentive rebates.¹² However, when respondents were asked to identify which factors were most important in deciding whether to drill, state tax incentives were ranked last of 10 possible choices. Factors that were more important included:

- Estimates of recoverable reserves;
- Geology of the prospect;
- Estimated cost to drill and complete proposed well;
- Price of oil/natural gas as shown in the futures market or at the time of decision to drill;
- Location of proposed well ;
- Drilling rig availability.

Of 23 respondents, 19 ranked state tax incentives among the three least important factors; none ranked them higher than fourth. Only three of 24 respondents said they always consider the availability of state tax incentives in deciding whether to drill, fewer than any other factor. Only 10 of 24 respondents stated that the availability of state tax breaks were influential in their decision to drill.

Prof. Agee concluded that incentives may matter "at the margin" -- in situations where the price of oil and gas is not so high that producers will choose to drill or so low that they will choose not to drill regardless. At the very least, this suggests that all oil and gas credits should be provided only when the price is below an established floor, as opposed to being provided regardless of price as is now the case for horizontal and deep well drilling.

Oil and gas tax preferences are not decisive for the profitability of drilling

There is no question that drilling horizontal and deep wells is more expensive than traditional drilling techniques. A new horizontal well drilled from the surface costs 1.5 to 2.5 times more than a vertical well.¹³ The Oklahoma City Geological Society has noted that for horizontal drilling, “Early production declines are very steep and drilling, operational (including water disposal) and acreage costs are high.”¹⁴ Some proponents cite these high production costs to justify the state’s preferred tax treatment of horizontal and deep well drilling.

“[In modern horizontal wells], the geological risk of a dry hole is essentially zero.”

But even with high drilling costs, horizontal and deep well drilling already have significant economic benefits for producers. The wells have considerably higher production rates and greater reserves than do vertical wells. Producers spend less time and money searching for oil, and operating costs for horizontal oil wells are lower: \$3 to \$4 per barrel in places where vertical costs are \$7 to \$9 per barrel.¹⁵ Similar advantages apply to natural gas.

In addition, in the growing range of reservoirs where horizontal drilling is now conducted, the economic risks are considerably less than with traditional vertical drilling. Dan Boyd explains the attractiveness of horizontal drilling plays: “Because they exist in low-permeability reservoirs in which fluid separation is not possible, the accumulations are continuous and the geological risk of a dry hole is essentially zero.”¹⁶

Boyd further notes that, “Even for isolated horizontal wells where economic risk is probably the greatest, the chance of a non-producing dry hole is usually less than the mechanical risk associated with drilling the wells.”¹⁷

This is not to say that horizontal and deep well drilling is necessarily profitable. Much depends on the price of oil and gas compared to production costs.¹⁸ But price-sensitivity is hardly unique to horizontal and deep well drilling compared to other forms of energy production or other market-driven economic activity. The fact that horizontal and deep well drilling may be unprofitable below certain prices provides no justification for tax incentives that subsidize production regardless of price.

Companies are unlikely to shift production elsewhere based on tax rates and tax preferences

Defenders of tax preferences, in the oil and gas sector as in other industries, often claim that states need to offer such assistance to compete successfully against other states, or even nations, that offer more favorable tax treatment. But there is no strong evidence that state tax rates and tax preferences have a major impact on decisions by energy companies on where to drill.

“The oil, natural gas, and coal industries are guided chiefly by the location of reserves, and are less able to relocate than are industries with mobile capital resources (such as textile mills or auto-makers),” according to by Headwater Economics, a research group that has extensively studied the energy industry.¹⁹ In other words, while you can move – or threaten to move – an auto-parts plant from Oklahoma to Alabama or Mexico in response to lower tax rates or more generous tax breaks, oil and gas reserves aren’t going anywhere. Among the array of factors that determine whether a company might choose to drill in Oklahoma instead of Alaska or Pennsylvania, state tax treatment in general, and tax subsidies in particular, are of minor importance.

Wyoming and Montana are good examples.²⁰ Both states in the late 1990s were experiencing a lull in energy production and sought to boost their economies. The Wyoming legislature commissioned two academic studies to evaluate the likely impact of tax and subsidy policies on the pace and scale of energy activities. The studies concluded that tax breaks would not stimulate significant new production or economic activity, but would cost the state millions in lost tax revenue. In fact, they found that higher tax rates would produce new revenues with little risk of slowing the energy economy.

In response, Wyoming repealed a 2 percent reduction in its severance tax rate granted in the previous year. At the same time, neighboring Montana reduced its severance tax rate on oil and gas, and added other subsidies that nearly exempted new production from severance taxes. As a result, the effective tax rate faced by the oil and gas industry is about 50 percent higher in Wyoming than in Montana.

Yet both states have enjoyed a surge in natural gas drilling since 2000. “New drilling continues in Wyoming at a faster pace than in Montana, and Wyoming’s energy economy is significant. There is little evidence in the overall figures to suggest that firms fled Wyoming’s higher tax climate and moved to Montana,” notes Headwater Economics.²¹ Both states enjoyed robust tax revenue growth in the early 2000s, but Wyoming’s outpaced Montana’s, allowing the state to more adequately fund education, transportation and other public services on which energy companies and other businesses depend.

Another reason state tax rates and tax preferences are unlikely to have a major impact on drilling decisions is that state gross production taxes are deductible from a company’s federal income tax liability. Companies that pay higher state taxes pay correspondingly less in federal taxes, and vice versa.²²

Depending on the commodity’s current and future price, Oklahoma will remain an attractive location to drill due to our ample oil and gas reserves, existing levels of production, skilled workforce, and established infrastructure. By comparison, state tax break are unlikely to be a significant factor in guiding a company’s decision to drill in Oklahoma or someplace else.

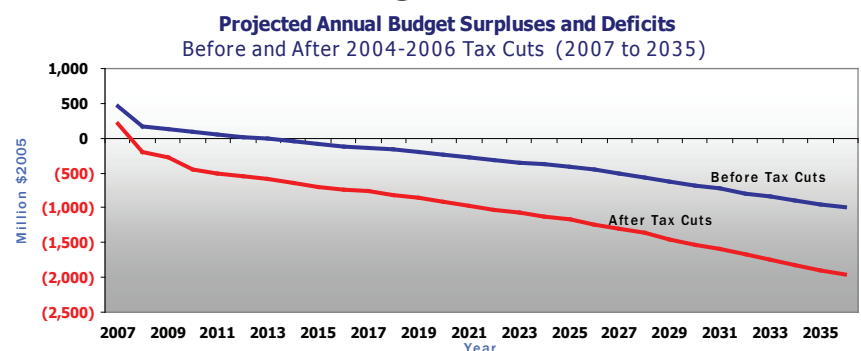
Recommendations: Repeal and Reform

In recent years, the economic downturn, along with tax cuts and tax breaks enacted by the Legislature, have created great strains on Oklahoma’s ability to meet growing public needs. Support for most services has been cut or held flat each of the past four years, and state funding remains below pre-recession levels, even before accounting for inflation or growth in population, school enrollment, and participation in numerous programs.²³

Looking ahead, the state faces what is called a *structural deficit*, an ongoing gap between the normal growth of state tax collections and the growing cost of meeting public needs. Many factors contribute to the gap, including the aging of the Baby Boom population, the state’s large unfunded pension liabilities, decaying infrastructure, and the likelihood of federal support to the states decreasing sharply.²⁴

There is no question that tax breaks for horizontal and deep well drilling are one of those factors, because they increasingly reduce the level of state tax collections. At the same time, they lack justification on job-creating, economic grounds.

Figure 4



Source: Projections conducted in 2007 by Dr. Kent Olson, Professor of Economics, Oklahoma State University

If lawmakers fail to curb these tax breaks, their cost is certain to escalate significantly in coming years, seriously threatening Oklahoma's ability to fund core public services and meet its financial obligations. In a time of scarce resources, it is counterproductive for Oklahoma to make unnecessary tax breaks to energy producers a higher priority than support for schools, health care, and infrastructure.

The Legislature should allow all gross production tax preferences to expire on or before their sunset date. Currently, the exemptions for horizontal and deep well drilling are due to expire July 1, 2015, while the other exemptions have a sunset date of July 1, 2014.

If lawmakers decide to continue the exemptions or keep them as interim measures until an eventual expiration, they should also adopt the following reforms:

- **Provide all drilling subsidies only when prices fall below a reasonable price floor.** As we have seen, tax preferences for most forms of production are limited to when oil and gas prices are below a statutorily-defined floor (\$5 per MCF of gas or \$30 per barrel of oil, indexed annually for inflation since 2011). The exceptions are for horizontal and deep well drilling, which qualify for the tax breaks regardless of price. There is no reason the state should subsidize production commodity prices are high. The credits for horizontal and deep well drilling should be subject to the same price floors as other forms of production.
- **Put an annual cap on gross production tax breaks.** In its final report on tax credits and economic incentives, the 2011 Task Force chaired by Rep. David Dank and Sen. Mike Mazzei unanimously endorsed setting limits on the dollar amounts that can be claimed under future tax credits "on an aggregate fiscal year basis or a dollar limit imposed on the task credit claimant or both such limitations."²⁵ The same rule should be applied to many existing credits, including those benefiting oil and gas production if these credits are not allowed to expire.

When credits are not subject to a cap, there is always a risk that their cost will balloon unexpectedly. That's what happened with deep well credit rebates before 2005 and with horizontal credits since. Policymakers were caught completely by surprise when the cost of gross production tax credits came in at \$294 million for FY '10 and FY '11. Without annual caps, there is no way to anticipate the future cost of gross production tax credits. Gross production tax credits could be capped at their existing levels, or as in the case of the 2005 legislation capping deep well credits, at levels more consistent with their historic cost.

Oklahoma law currently caps various tax preferences, including the Quality Investment program, investments in agricultural processing cooperatives, and the Oklahoma Film Enhancement rebate.²⁶

- **Tax horizontal drilling at the same rate as deep well drilling.** As we have seen, the tax treatment for horizontal drilling is more favorable than any other form of production. Along with or instead of putting a price trigger or an annual cap on horizontal drilling credits, oil and gas that is extracted through this production could still be taxed at less than the full 7 percent but at a higher rate than 1 percent – perhaps at the same 4 percent rate as deep well drilling. In addition, the preferential tax rate could be claimed only until project costs are recovered, rather than for a full 48 months.

Appendix: Summary of Oklahoma Gross Production Tax Exemptions, as of FY '11

(boxes in yellow represent exceptions to general rules)

Kind of drilling	Statutory Section	Kind of well	Exemption applicable to	Amount of exemption	Subject to price? (1)	Length of exemption	Alternative production date	Sunset Date
Enhanced recovery projects	§§ 05 2001.10	Secondary recovery	Incremental production attributable to the working interest owner	Full	No	5 years or termination of the secondary recovery project	Project beginning date prior to 7/1/2012	7/1/2014
		Tertiary recovery projects			No	10 years or until project payback is achieved		
Normally drilled wells	§§ 05 2001.11	Well producing after 7/1/04	Production of oil, gas or of and gas		No	48 months or until project payback is achieved	Producing prior to 7/1/2011	7/1/2015
						48 months from the month of initial production	Producing on or after July 1, 2011 or prior to July 1, 2015	
Drilled well	§§ 05 2001.12		Revenant or production of oil, gas or of and gas	4/7004	Yes	20 months from the date of the first well operation	Project beginning date prior to 7/1/2012	7/1/2014
Production enhancement wells	§§ 05 2001.14		Incremental production	4/7004	Yes	20 months from the date of the first well operation	Project beginning date prior to 7/1/2012	7/1/2014
Deep wells	§§ 05 2001.124 and 24,000.05		Production of oil, gas, or of and gas		Yes	20 months from the date of first well	Well-spludded before 2/1/2010	7/1/2014
				Depth between \$2,900 and \$4,000				
Water-Completion	§§ 05 2001.123 and 27,000.05		Production of oil, gas, or of and gas			48 months from the date of first well	Wells spludded before 7/1/2015	7/1/2015
				Depth between \$4,000 and \$7,000				
				Depth of \$7,000 to or less		60 months from the date of first well	Well-spludded or reworked before 2/1/2010	7/1/2014
New discovery	§§ 05 2001.11		Production of oil, gas, or of and gas	4/7004	Yes	20 months from the date of first well	Re-worked before 2/1/2010	7/1/2014
				Production of oil, gas, or of and gas	4/7004	Yes	20 months from the date of first well	2/1/2014
Three-dimensional drilling	§§ 05 2001.11		Production of oil, gas, or of and gas	4/7004	Yes	20 months from the date of first well	Drilling commenced before 2/1/2010	7/1/2014

(1) Exemptions subject to price apply only if price of oil <\$20.00 per barrel or price of gas <\$3.00 MCF, adjusted annually for inflation

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