

**State of Alaska**  
Department of Revenue  
*Commissioner's Office*



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January 21, 2010

Speaker Chenault

Representatives Ramras, Johnson, Johansen, Hawker, Millett, Austerman, Stoltze,  
Dahlstrom, Wilson, Edgmon, Munoz, Herron, Harris, and Seaton

Senator Huggins

State Capitol Building

Juneau, Alaska 99801-1182

Dear Legislators:

The attached information is in response to the December 4, 2009 letter addressed to Governor Parnell each of you signed regarding Alaska's current oil and gas production tax and recent industry activity. The Governor requested that the Department of Revenue compile the requested information and provide this response. The information attached to this letter was provided by the Departments of Revenue, Natural Resource, and Labor and Workforce Development, as well as the Alaska Oil and Gas Conservation Commission.

Your letter stated that it was motivated by a concern that evidence indicated oil industry activity is declining, and you wanted to gather data to determine if the declining activity is due to excessive taxation. This response document answers each of your questions, and provides the requested data. As you will see from the data, the level of industry investment has increased each year since the enactment of the Petroleum Production Tax (PPT) in 2006 and Alaska's Clear and Equitable Share (ACES) in 2007. Employment in the industry has risen steadily during the same period with preliminary results indicating 2009 to be the highest in state history. However, the data also reveals that the period from 2005 to the present experienced less drilling activity than the previous five-year period.

With regard to Alaska's overall attractiveness for new oil and gas investment, it is important to recognize that an evaluation cannot be limited to review of the fiscal system. As the Governor points out in his December 11, 2009 response to Speaker Chenault, investment decisions by the

industry are influenced by several factors, including geology, infrastructure, support service costs, regulatory and global economic considerations, in addition to the state's fiscal system.

The Governor shares the objective contained in your letter of providing a state fiscal system that both encourages new investment and provides a fair share of revenue to the state. The information provided in this response, as well as the results of the ACES Status Report, released by the Department of Revenue last week, led me to recommend amendments to the production tax system. To that end, the Governor will be introducing legislation pursuing specific amendments to ACES and the Exploration Incentive Credit (EIC) program which will further incentivize infill drilling and well work, level the playing field between incumbents and explorers, eliminate administrative difficulties, and deal more fairly with taxpayers.

If you need more information than that provided in the following response, please let us know.

Sincerely,

A handwritten signature in black ink, appearing to read 'P. Galvin', followed by a long horizontal line extending to the right.

Patrick S. Galvin  
Commissioner

CC: Governor Parnell  
All Legislators  
Tom Irwin, DNR  
Click Bishop, DOL  
Cathy Foerster, AOGCC

## Response to Information Requests in December 4, 2009 Letter

*Prepared by the Department of Revenue, Department of Natural Resources, Department of Labor and Workforce Development, and the Alaska Oil and Gas Conservation Commission*

1. For each year, 2005 through 2009, what was the average number of bidders and average dollar amount per acre for each oil and gas lease property offered by the state?

Table 1 shows the average number of bidders and average dollar amount received for leases during each year from 2005 through 2009. The results show no clear trend during the specified time period. Yearly variance most likely reflects the relative attractiveness of the acreage available in each lease sale. The volume and quality of the leases offered each year varies depending upon the expiration of existing leases and the perceived geologic quality of the available acreage. As a result, average results can be affected significantly by interest in a single lease.

**Table 1. Alaska Oil and Gas Leases, Avg. \$ Per Acre and Number of Bidders, 2005-2009**

Year	Avg. \$/Acre	Avg. Number Bidders/LeaseSale
2005	\$5.92	5.3
2006	\$20.17	8.2
2007	\$10.74	3.2
2008	\$19.74	5.0
2009	\$11.51	3.3

2. What are the employment numbers attributable to the oil and gas industry in Alaska per year, 2005 to 2009, expressed in terms of average annual employees and average annual salary? How do the actual numbers for 2005 through 2009 compare to the employment numbers forecast by the state in the year or period?

Table 2 shows the actual statewide oil and gas industry employment and earnings from 2005-2009 along with the employment levels forecasted by the Department of Labor and Workforce Development during the preceding year. Calendar year 2008 marked the highest level of industry employment in the state's history. Although employment

estimates for 2009 are still preliminary, it is projected to exceed employment in 2008. Additional employment data extending back to 1980 is included in the ACES Status Report, released by the Department of Revenue last week.

**Table 2. Alaska Oil and Gas Average Earnings and Forecasted and Actual Employment, 2005-2009**

Year	Actual Employment	Forecasted Employment	Avg. Annual Earnings
2005	8,700	8,300	\$ 99,224
2006	10,100	9,000	\$ 102,675
2007	11,500	10,300	\$ 108,566
2008	12,800	11,600	\$ 113,541
2009*	13,000	12,700	

\*preliminary employment estimate; earnings are not available for 2009

- Has there been a reduction in the number of new drilling permits since the enactment of the PPT and ACES? Was there a change in the number of applications projected after the enactment of PPT compared with the number projected after the enactment of ACES?

In Alaska, a Permit to Drill is required for each new well. Table 3 shows the total number of new Permits to Drill approved by the AOGCC by month, from January 2000 through December 2009. These values are charted in Figure 1, along with monthly average WTI crude oil prices and the enactment of PPT and ACES.

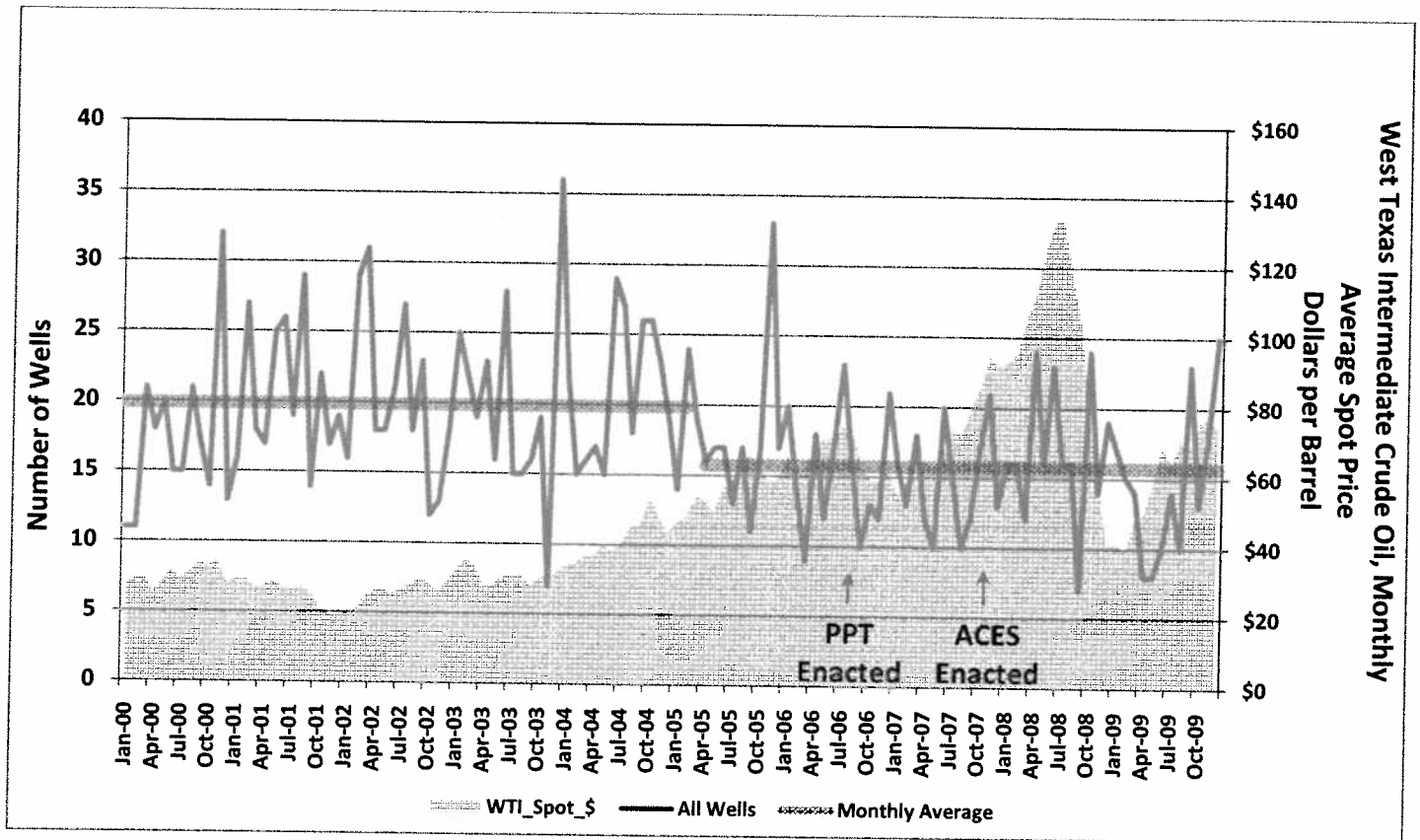
**Table 3. Monthly Counts of All Drilling Permits 2000 to 2009**

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Jan	11	16	16	25	22	14	20	16	16	17
Feb	11	27	29	22	15	24	14	13	16	15
Mar	21	18	31	19	16	19	9	18	12	14
Apr	18	17	18	23	17	16	18	12	24	8
May	20	25	18	16	15	17	12	10	16	8
Jun	15	26	21	28	29	17	17	20	23	10
Jul	15	19	27	15	27	13	23	15	16	14
Aug	21	29	18	15	18	17	16	10	16	10
Sep	17	14	23	16	26	11	10	12	7	23
Oct	14	22	12	19	26	17	13	17	24	13
Nov	32	17	13	7	23	33	12	21	14	18
Dec	13	19	18	36	19	17	21	13	19	25
<b>Yearly Total</b>	<b>208</b>	<b>249</b>	<b>244</b>	<b>241</b>	<b>253</b>	<b>215</b>	<b>185</b>	<b>177</b>	<b>203</b>	<b>175</b>

2000-2004 Yearly Avg: 239.0  
 Monthly Avg: 19.9

2005-2009 Yearly Avg: 191.0  
 Monthly Avg: 15.9

**Figure 1. Number of Drilling Permits Approved January 2000 to December 2009**



The figure indicates a slight downturn in the average numbers of wells permitted between the periods of 2000-2004 (19.9) and 2005-2009 (15.9). These values are represented by the thick horizontal lines in **Figure 1**. This occurred prior to the enactment of PPT or ACES. It is unclear, however, what specifically may have caused the downturn in permitting. Generally speaking, industry activity is most closely correlated with oil prices, which climbed rather steadily through the period in which permitting declined.

It is not possible to compare these results with application projections as these are not currently compiled by any state agency.

**4. What is the number for active drilling rigs per month from 2005 through 2009?**

**Figure 2** and **Table 4**, on the next page, show the estimated number of rigs conducting drilling and workover (repair of existing wells) activities during each quarter from 2005 to 2009. This information is taken from field inspector's blowout prevention test

reports filed with the AOGCC. The number of active rigs remained relatively flat after enactment of PPT, increased for the first five quarters following the enactment of ACES then fell sharply during the first three quarters in 2009.

Remedial well work activity level also impacts drilling because often the same rigs are used for both activities. Thus, an increase in remedial well work (i.e., fixing broken wells) usually results in a decrease in drilling activity level.

Figure 2. Active Rigs 2005 to 2009

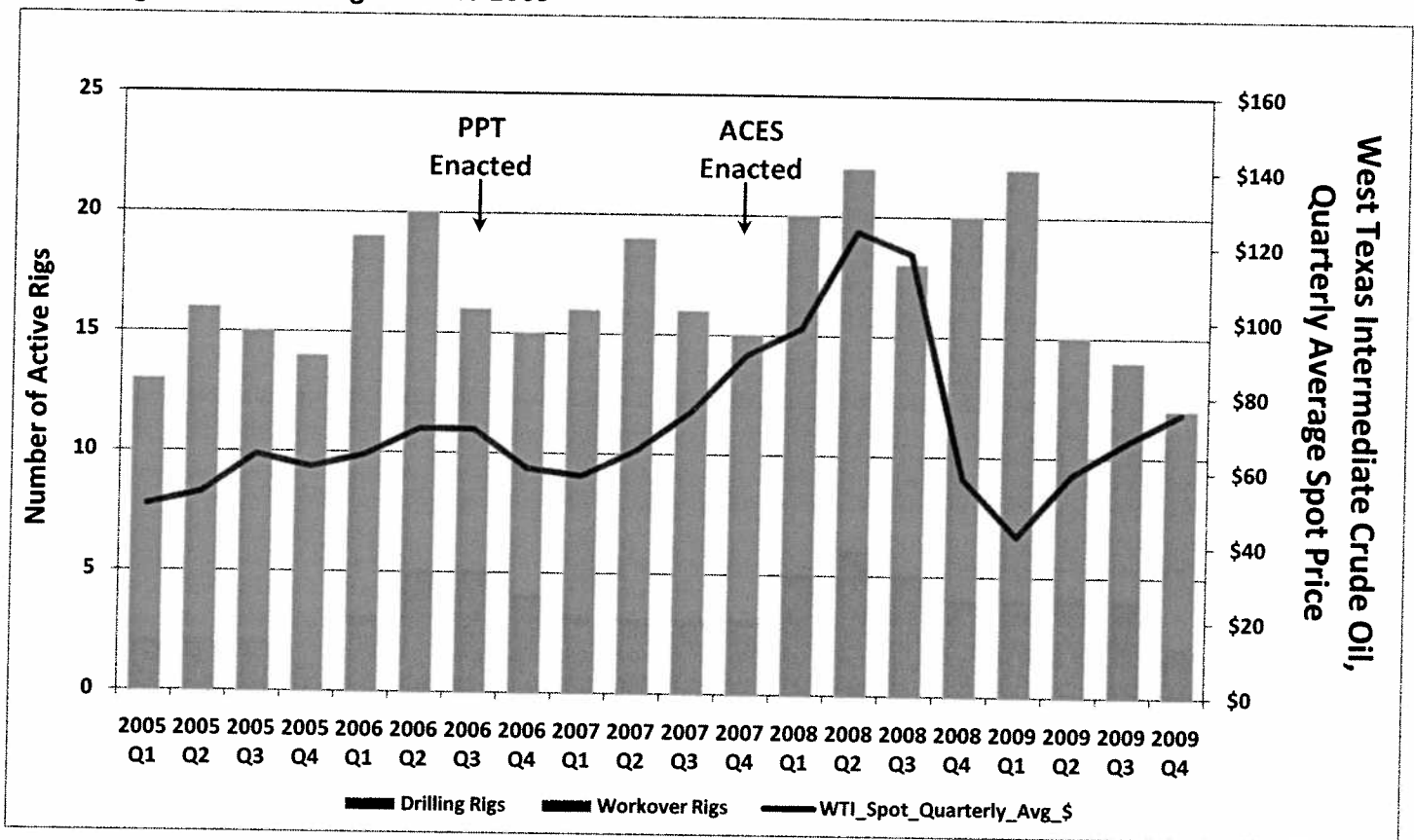


Table 4. Quarterly Counts of Active Rigs 2005 – 2009

Rig Type	2005				2006				2007				2008				2009			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Drilling	11	14	13	13	16	15	11	11	13	16	13	12	15	16	13	16	18	11	10	10
Workover	2	2	2	1	3	5	5	4	3	3	3	3	5	6	5	4	4	4	4	2
<b>Total</b>	<b>13</b>	<b>16</b>	<b>15</b>	<b>14</b>	<b>19</b>	<b>20</b>	<b>16</b>	<b>15</b>	<b>16</b>	<b>19</b>	<b>16</b>	<b>15</b>	<b>20</b>	<b>22</b>	<b>18</b>	<b>20</b>	<b>22</b>	<b>15</b>	<b>14</b>	<b>12</b>

2005 Avg: 14.5

2006 Avg: 17.5

2007 Avg: 16.5

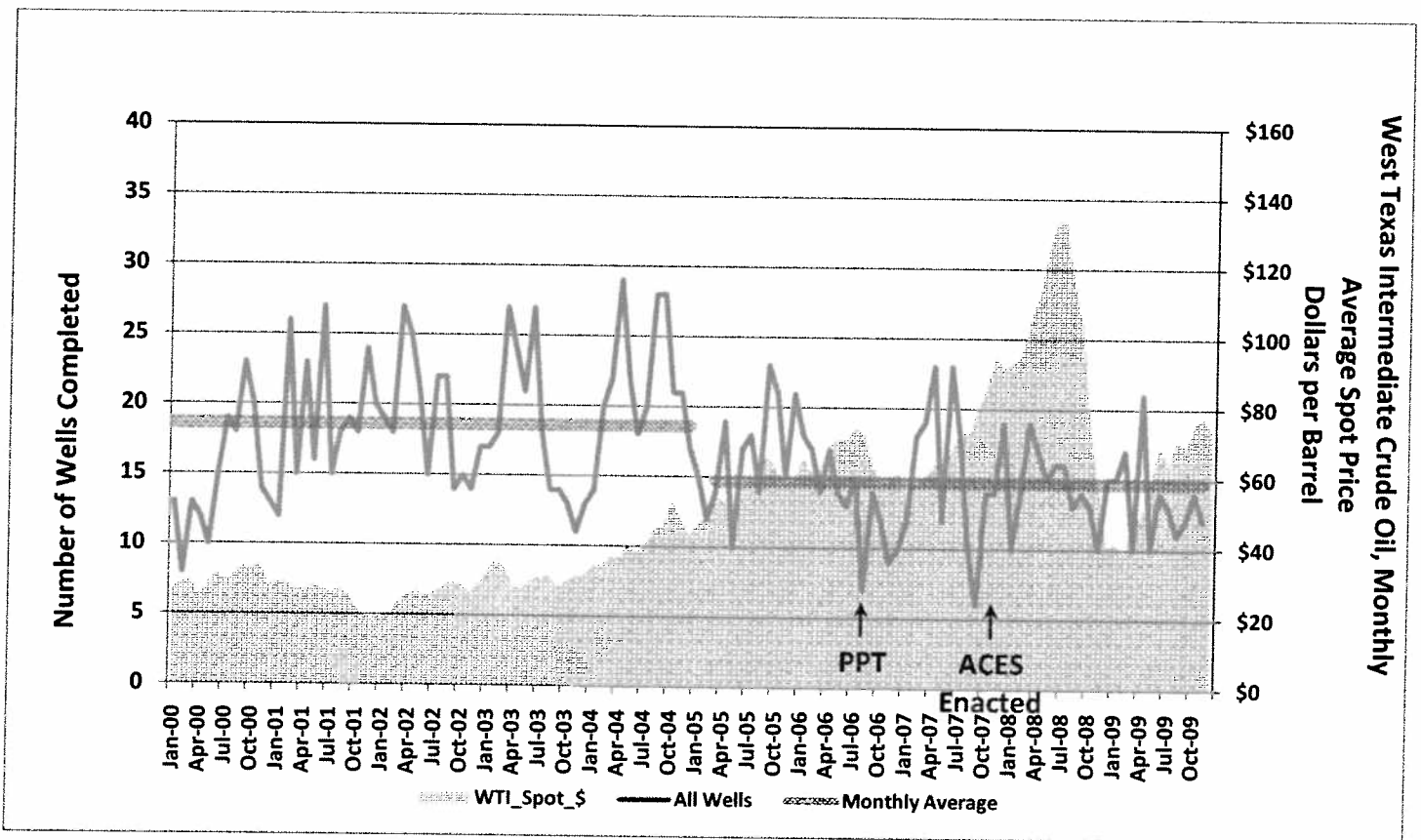
2008 Avg: 20.0

2009 Avg: 15.8

4. (Continued) What is the number of new holes drilled per month from 2005 through 2009?

Figure 3 and Table 5 display the number of wells drilled and completed in Alaska from January 2000 through November 2009 (the count for December 2009 is not yet available due to the 6-week reporting and processing period). As with Figure 1 and Table 3, the average number of wells drilled and completed each month for the periods from 2000-2004 and 2005-2009 are indicated by the thick, horizontal lines. As stated earlier, while the data shows a decline in the average number of wells drilled and completed each month, it appears that this downward trend began prior to the enactment of the PPT and ACES.

Figure 3. Wells Completed 2000 - 2009



**Table 5. Monthly Counts of New Wells Drilled and Completed 2000-2009**

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Jan	13	12	19	17	14	15	18	12	10	15
Feb	8	26	18	18	20	12	17	18	14	17
Mar	13	15	27	27	22	14	14	19	19	10
Apr	12	23	25	24	29	19	17	23	17	21
May	10	16	21	21	22	10	14	12	15	10
Jun	15	27	15	27	18	17	13	23	16	14
Jul	19	15	22	18	20	18	15	18	16	13
Aug	18	18	22	14	28	14	7	10	13	11
Sep	23	19	14	14	28	23	14	6	14	13
Oct	20	18	15	13	21	21	12	14	13	15
Nov	14	24	14	11	21	15	9	14	10	12
Dec	13	20	17	13	17	21	10	19	15	
<b>Yearly Total</b>	<b>178</b>	<b>233</b>	<b>229</b>	<b>217</b>	<b>260</b>	<b>199</b>	<b>160</b>	<b>188</b>	<b>172</b>	<b>151</b>

2000-2004 Yearly Avg: 223.4  
 Monthly Avg: 18.6

2005-2009 Yearly Avg: 174.0  
 Monthly Avg: 14.7

**5. How many drilling permits has the [AOGCC] issued, month by month, from January 2005 through November 2009?**

The AOGCC issues three classifications of Permits to Drill. These include separate permits for exploratory, development, and service wells. These are shown in aggregate in **Figure 1** and **Table 3** above (see question 3). As stated earlier, this data suggests a downturn in the total number of permits beginning in 2005, prior to the enactment of PPT and ACES.

**Figure 4** and **Table 6** on the next page, show the monthly counts of Permits to Drill approved only for exploratory wells. These figures do not include development or service well permits. The figure does not show any obvious trends with respect to the enactment of PPT or ACES.

Figure 4. Exploratory Wells Permitted 2000 to 2009

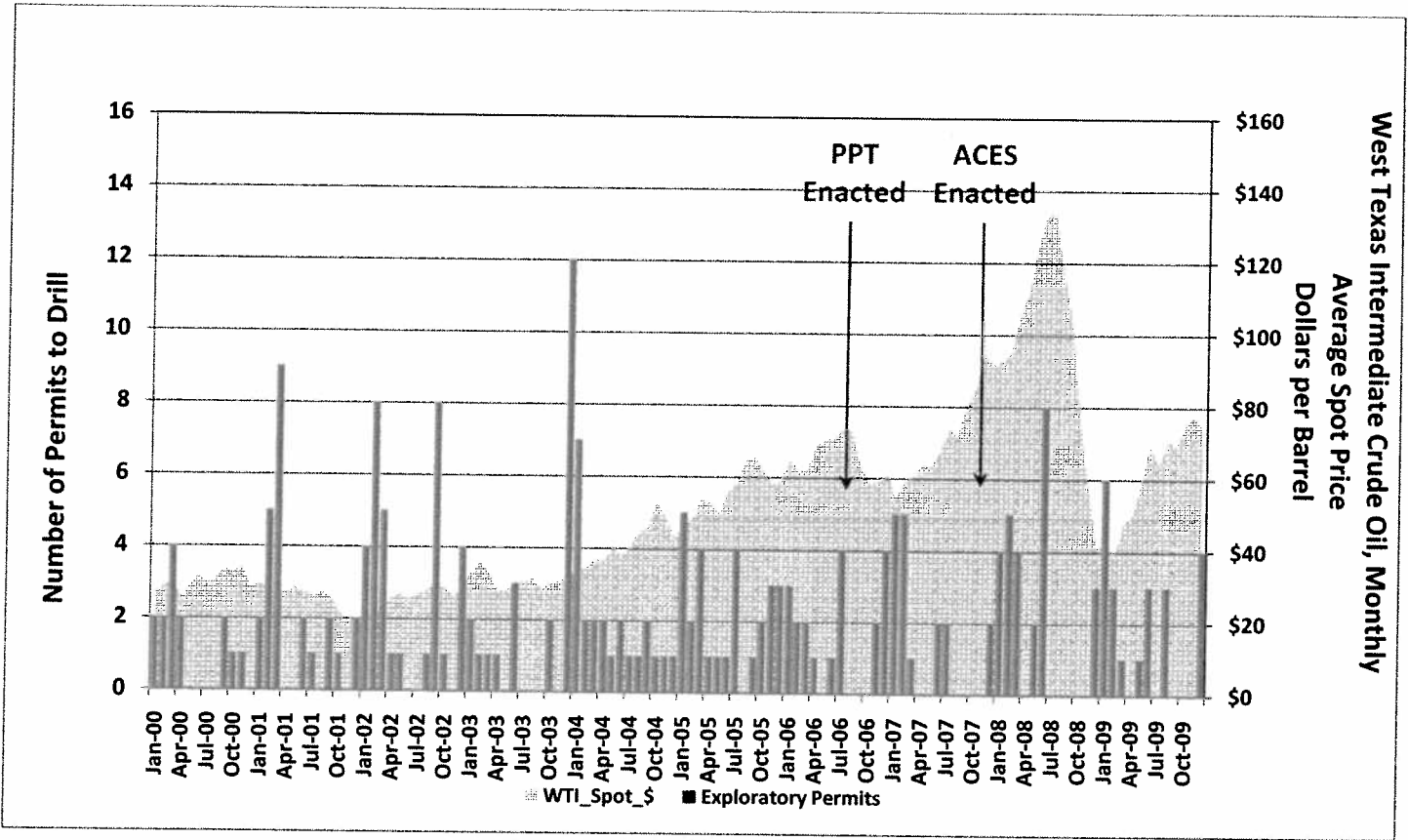


Table 6. Monthly Counts of Exploratory Wells Permitted 2000 to 2009

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Jan	2	2	4	2	7	5	3	5	4	6
Feb		5	8	1	2	2	2	5	5	3
Mar	4	9	5	1	2	4	2	1	4	1
Apr	2		1	1	2	1	1			
May			1		1	1			2	1
Jun		2		3	2	1	1	2	8	3
Jul		1			1	4	4	2		
Aug			1		1					3
Sep	2	2	8		2	1				
Oct	1	1	1	2	1	2				
Nov	1				1	3	2			
Dec		2	4	12	1	3	4	2	3	4
<b>Yearly Total</b>	<b>14</b>	<b>24</b>	<b>33</b>	<b>22</b>	<b>23</b>	<b>27</b>	<b>19</b>	<b>17</b>	<b>26</b>	<b>21</b>

2000-2004 Yearly Avg: 23.2

2005-2009 Yearly Avg: 22.0

- 6. Has the industry increased its level of exploration and development in general and, in particular, increased interest in the development of smaller fields? Has the response to the enactment of the credits been consistent with the response expected at the times PPT and ACES were enacted compared with the credits in effect before the enactment of PPT and ACES?**

Indicators of new industry activity in Alaska show mixed results. As shown in the ACES Status Report, released last week, industry spending has generally increased steadily since the enactment of PPT and ACES. Capital spending during FY 2009 was roughly twice the level of 2003 and 2004. At least some of this increase is due to the development of new major projects including Oooguruk, Nikaitchuq and Point Thomson.

New expenditure and forecast reporting requirements under PPT and ACES are allowing the department to develop a much better understanding of true field costs and development plans. However, inconsistent and limited historical data make comparisons with earlier data less reliable. Nevertheless, over the next several years, taxpayer forecasts show capital spending increasing. Based on a review of taxpayer reports, the growth of overall capital spending is primarily attributable to drilling, seismic, and other projects, and not pipeline repairs or other maintenance costs.

As noted above in question 5 (**Figure 4** and **Table 6**), no obvious trends are seen in the number of new exploratory well permits issued by the AOGCC. The same is true for the number of exploratory wells completed each month, as indicated on the following page in **Figure 5** and **Table 7**.

Figure 5. Exploratory Wells Completed 2000 to 2009

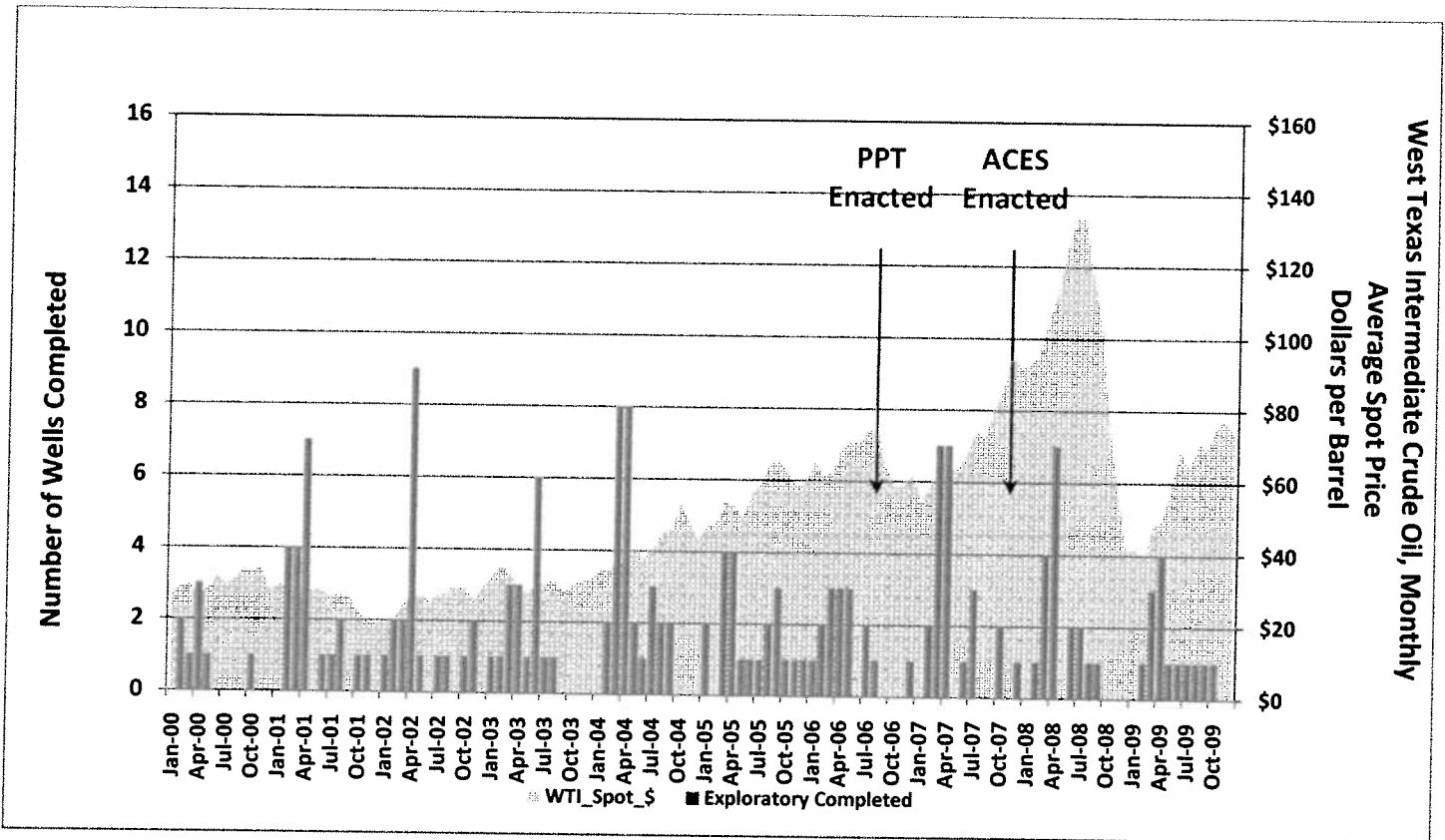


Table 7. Monthly Counts of Exploratory Wells Completed 2000 to 2009

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Jan			1	1		2	1			
Feb	2	4	2	1	2		2	2	1	1
Mar	1	4	2	3	8	4	3	7	4	3
Apr	3	7	9	3	8	4	3	7	7	4
May	1		1	1	2	1	3			1
Jun		1		6	1	1		1	2	1
Jul		1	1	1	3	1	2	3	2	1
Aug		2	1	1	2	2	1		1	1
Sep					2	3			1	1
Oct	1	1	1			1		2		1
Nov		1	2			1				
Dec						1	1	1		
<b>Yearly Total</b>	<b>8</b>	<b>21</b>	<b>20</b>	<b>17</b>	<b>28</b>	<b>21</b>	<b>16</b>	<b>23</b>	<b>18</b>	<b>14</b>

2000-2004 Yearly Avg: 18.8

2005-2009 Yearly Avg: 18.4

The data show both gaps (intervals with no exploratory drilling) and spikes (intervals with several exploratory wells drilled), but little correlation to prevailing oil prices. Although the annual average for exploratory wells drilled and completed dropped

slightly from 2000-2004 to 2005-2009 (from 18.8 to 18.4), the difference is negligible given the significant variability from month to month.

The exploration incentive credits program authorized under AS 43.55.025 was implemented in the fall of 2003. Since inception, this credit program has received 57 applications for credits, totaling \$329 million. The 57 applications represented credits sought for exploration activity in the years shown below in **Table 8**.

**Table 8. Yearly Credit Applications**

<b>Year Work Performed</b>	<b>Applications for Credit</b>
2003/2004	8
2005	7
2006	7
2007	9
2008	21
2009*	5

\*Data is for partial year only

Of these credit applications, about 70% of the credits for which applications were received were for work performed after the passage of PPT and later ACES. It is possible that the run-up in applications for work performed in 2008 were related to the extraordinarily high oil prices that were posted that year. Likewise, the decline in applications for work performed in 2009 could be due to lower oil prices in addition to the world economic crisis and dampened oil demand.

Company-reported expenditures show a similar pattern when considering investment in the undeveloped areas of the North Slope. Companies report that capital expenditures in the non-unitized areas of the North Slope (primarily NPR-A) were \$247 million in 2007, \$191 million in 2008, and \$54 million in 2009 (partial year). Exploration and drilling seasons generally occur in the winter months and prices began to rise significantly in the last quarter of 2007, continuing into 2008.

Although company expenditure information prior to the passage of PPT and ACES is only evidenced by the amount of expenditures claimed under credit applications, it appears as though expenditures were not more than \$100 million in either of the two pre-PPT years that the exploration incentive credit was in place.

- 7. Are the lease expenditures, including capital expenditures, that are permitted under the PPT and ACES effective in developing enhanced recovery projects and extending the period in which production from a particular field is commercially viable? Are there significant expenditures that are not currently allowed as lease expenditures that should be or lease expenditures that are allowed that are irrelevant or unnecessary?**

The AOGCC, which regulates field development, requires that all necessary enhanced recovery techniques be used from the beginning of field life in order to maximize hydrocarbon recovery. To the extent not excluded by statute, both the capital and operating components related to the exploration, development, or production from a field will be allowable as lease expenditures, and, to the extent that an expenditure qualifies as a capital credit, a producer would also be allowed a credit of 20% of the qualifying expenditures to be applied against its production tax liability.

The department is in the final stages of a lengthy process of developing regulations defining allowable lease expenditures under ACES. After numerous public workshops involving stakeholder input, the regulations are expected to be finalized this month. This has been additionally complex as regulations were never fully issued under the previous PPT tax.

Various expenditures were excluded from being considered "lease expenditures" under AS 43.55.165(e). They included fines and penalties; income taxes; lease acquisition costs; depreciation and depletion costs; royalty costs; dismantlement and abandonment costs; environmental clean-up costs; repair and replacement costs associated with unscheduled production disruptions; construction and operation costs of refineries and crude oil topping plants; and lobbying and public relations costs. There was significant debate during the ACES Special Session concerning whether an exception to the refinery exclusion should be made for the costs associated with retrofitting an existing diesel refinery plant to become an Ultra-Low Sulfur Diesel (ULSD) Refinery on the North Slope. Testimony from Conoco Phillips, one of the owners of the facility, was that without the state subsidy provided by having the development costs deductible, the plant would not be economic. Instead of making their own diesel, the North Slope producers are instead purchasing diesel refined in Kenai or Fairbanks and paying to have the diesel transported to the Slope. These producer costs are deductible under ACES. Apart from these costs, the Department of Revenue is unaware of any other significant expenditures that are currently not allowed as lease expenditures. The enabling statute at AS 43.55.165(a)(1)(B)(ii), requires that a lease expenditure be an ordinary and

necessary cost of producing oil or gas deposits. As such, there are no lease expenditures that are allowed that are irrelevant or unnecessary.

- 8. In general, considering the tax credits, allowable lease expenditures, and the tax rates in ACES, what effect have the changes had on the level of new exploration, development, and enhanced oil recovery projects? In particular, are the tax credits offered in ACES sufficient to encourage new exploration and development? Does the effective tax rate have an effect on new exploration and development and enhanced recovery projects in existing fields?**

It is difficult to determine what direct impact recent changes in the state's production tax may have had on oil and gas industry investment, given the analysis to date and the limited timeframe in which ACES has been in place. Many indicators nevertheless show generally positive trends in recent industry spending and in expenditure projections.

Since the enactment of PPT, almost \$1 billion in capital expenditure credits have been applied to offset tax liabilities for companies that have current production. The amount of credits issued, either through offset of tax liabilities, or in the form of direct cash refunds, equate to roughly 10% of the total amount of production tax revenue collected by the state under both PPT and ACES during the three years since implementation.

Meanwhile the average number of exploratory wells and exploratory well permits appear to have dropped prior to the enactment of PPT or ACES and it is unclear what may have caused this.

While the fiscal system of a given jurisdiction is recognized as a significant factor affecting investment decisions, it is difficult to isolate this factor from other significant influences including access to resources and markets, legal and regulatory frameworks, macroeconomic factors and access to skilled labor and infrastructure.

The Exploration Incentive Credits under AS 43.55.025 (discussed above in question 6), were implemented in late 2003, with credit rates of 20% and 40% of expenditures, based on specified criteria. When PPT was enacted, there was little incentive to pursue the 20% credit under AS 43.55.025, because PPT offered a separate 20% Capital Tax Credit under AS 43.45.023 for all capital expenditures, without requiring all of the paperwork necessary for filing under AS 43.55.025. This response was noted when ACES was introduced, and the credits under AS 43.55.025 were increased to 30% and 40%, respectively. While more time will be needed to see how this affects exploration

investments, it is anticipated that this change will result in additional Exploration Incentive Credits being sought under AS 43.55.025.

The investment incentive impact of credits, as well as the ability to deduct lease expenditures on existing fields, is more difficult to measure. Total capital expenditures on the North Slope have held steady over the past three fiscal years, with totals of \$2.0 billion, \$2.0 billion, and \$2.2 billion, in FY 2007, FY 2008 and FY 2009. In the department's Fall 2009 revenue forecast, based in large part on taxpayers' submitted expenditure forecasts, capital expenditures are projected to increase in FY 2010 to \$2.5 billion. Including operating expenditures, the total amount of qualified lease expenditures for FY 2010 is projected to be \$4.5 billion.

DOR has observed that as oil prices increase or decrease, so do company capital expenditure projections. The company-provided projections made in Fall 2008, one year after ACES passed, pegged total North Slope capital expenditures in FY 2010 at \$5.4 billion. One year later, with oil prices as much as \$50 lower, the projections for FY 2010 had been adjusted downward to \$4.5 billion.

- 9. What recommendations does the administration have for changes to ACES that will encourage exploration and development for the oil and gas industry in the state and, in particular, encourage exploration to guarantee sufficient oil in TAPS for its ongoing operation?**

Sufficient Oil in TAPS for its Ongoing Operation

Recent claims that TAPS may be shut down as early as 2018 are without technical merit. While operational issues will develop as oil throughput decreases, TAPS is not in danger of shutting down any time soon. More reasonable estimates, based on known oil reserves, place the end of TAPS operation beyond the 2040's. This projection will continue to be pushed out as new discoveries are made and new fields are brought on line.

The state has a clear interest in maximizing the throughput of TAPS both now and into the future. This is one of the many reasons that the administration has supported exploration and development of federal leases in the Outer Continental Shelf (OCS). Although the state will not receive the same royalty or tax revenue from these leases, it will indirectly impact state revenue by helping to reduce the tariff for all oil transported through TAPS.

While increasing TAPS throughput is the goal, the state also has to evaluate the risks associated with declining throughput. The problems that arise from low oil throughput are manageable, and manifest in two main forms. These include inefficiencies with pumping and changes from turbulent to laminar oil flow. The large turbine engines originally installed in the pipeline were single speed pumps designed to handle higher volumes (closer to 2 million bbl/day). The inefficiency associated with using these at lower volumes has kept operating costs for the pipeline relatively high. This issue, however, has been largely addressed through the recent strategic reconfiguration of TAPS, in which some pump stations were shut down and others were replaced with more efficient variable speed pumps.

The other significant issue for TAPS is for the oil to maintain a state of "turbulent" flow. That is, the oil swirls and bounces around in the pipe, keeping it mixed up along with any entrained sediment. When oil flow decreases, flow can become "laminar," where the oil moves in a more static fashion. The problem with laminar flow is that it allows sediments and water to drop out of the mixture, which can in turn cause a number of serious problems.

There are various potential remedies for this, but it remains an issue which the pipeline operators will continue to work over the coming years. The more significant question from the state's perspective is at what point will laminar flow begin? The Department of Revenue currently uses 200,000 bbl per day, based on public statements from Alyeska and their reported minimum scalability of the newly installed pumps. While there is continued dispute over this number (largely because of its impact on TAPS property taxes), most parties believe that TAPS can be comfortably operated at or below this level.

#### Recommended Changes to ACES

Based primarily on the ACES Status Report, the Commissioner of Revenue made recommendations to the Governor for amendments to ACES and the Exploration Incentive Credit (EIC) program. The Governor has announced his plan to introduce legislation to pursue the Commissioner's recommendations. The recommended amendments are:

1. Increase Credits for All Well-Related Activity to 30%: The Capital Credit and Exploration Incentive Credit (EIC) programs have been identified as influential in spurring exploration activities. However, the EIC program's 30% credits are only available to wells located more than 3 miles from all existing wells. The state has a

significant interest in also incentivizing infill drilling and other well work that will increase oil production, particularly for heavy oil. This proposal will expand the EIC program so that all expenditures related to drilling and well work that add new production or increase the efficiency of existing production will qualify for the 30% EIC credit under AS 43.55.025 regardless of a well's location relative to existing wells.

2. Increase Access to Capital Credits for New Explorers: Small producers are currently required to invest in new activities during subsequent years in order to obtain direct payment from the state for previously earned tax credits. This is not an issue for existing producers because they simply deduct credits from their current tax bill and do not need to seek direct payment from the state. Deleting this provision would make the tax credits more accessible to smaller explorers, level the playing field between new and existing operators, and eliminate an unfair double standard.
3. Accelerate Capital Credit Usage: Companies currently can only use half of their capital credits in the year they are earned, and the other half the following year. This is true whether the credits are applied against a tax liability or purchased by the state. Taxpayers would see increased value in the credits if they could apply the entire credit in the first year. In addition, this would ease the cost of administering these credits.
4. Waive Interest on Late Tax Payments Due to Drafting of Regulations: The ACES regulations, including those defining 'allowable lease expenditures' are being finalized this month. Under the statutes, these regulations are to be applied retroactively to various dates in 2007. To the extent additional taxes are due as a result of the application of the new regulations, such payments would be subject to interest and possibly penalties. While the department can waive penalties, it cannot waive interest charges. A statutory change is required in order to permit the waiver of interest.