

AK LEGISLATURE FINANCE COMMITTEES FILES 2007-2008 3287

Conclusions

- **Corrosion Repair and “Integrity Management” Efforts Likely to Increase Costs Reported for Alaska, Even for Non-Corrosion Repair Services.**
- **SEC Filings Suggest that Corrosion Repair and “Integrity Management” Costs are Likely Included in Alaska Figures.**
- **DOR Forecasts Likely Include Costs Related to These Efforts.**
- **DOR Cost Estimates Now Include Cost / Price Sensitivity. This is Appropriate.**
- **A Proper Determination of the Actual Costs will Require Examination of Supporting Materials. Examination Should Include a Review of Unit-by-Unit Information Both During the PPT Period and Several Years Prior to the Implementation of PPT.**



REPORT TO THE ALASKA LEGISLATURE ON PRODUCTION COST INCREASES

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November 2, 2007

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Report to the Alaska Legislature on Production Cost Increases

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I. Introduction

This report addresses issues raised in Senator Therriault's August 30, 2007 letter on PPT lease costs. In preparing this report we have,

- reviewed the modeling used for the Alaska Department of Revenue's (DOR) Fiscal Note accompanying HB 3001;
- reviewed DOR's August 3, 2007 PPT Status Report;
- interviewed DOR personnel familiar with the DOR models, cost assumptions and PPT filings by the producers;
- reviewed various presentations made during PPT hearings last year;
- reviewed SEC filings made by producers;
- reviewed data compiled by the Energy Information Agency regarding production costs;
- reviewed reports prepared by market analysts regarding production costs; and
- reviewed cost information regarding drilling rig rates in the Lower 48 states.

II. DOR Forecast Lease Cost Increases Generally

The Alaska Department of Revenue (DOR) issued a "PPT Status Report" on August 3, 2007. In that report, the DOR stated that for FY 2008, revenues were expected to be \$800 million lower than earlier forecasts, as reflected in the Fiscal Note accompanying HB 3001. The DOR Status Report is included here as Attachment 1.

The DOR identified higher than forecast costs as the primary reason for the decrease in projected revenues. Relative to the HB 3001 Fiscal Note, the DOR forecast lease cost increases for FY 2008 of nearly \$2 billion. This represents an approximate 100% increase in costs. Capital cost forecasts increased by \$1.1 billion, while operating costs increased by \$0.9 billion. The impact of increased costs forecasts would account for the reduction in forecast revenues of approximately \$800 million as set forth in the Status Report.

In the Fiscal Note accompanying HB 2001 (ACES), the DOR has increased its cost increases further. The DOR currently projects total operating and capital costs for FY 2008 of \$4.33 billion, an increase of approximately 7% over the figures set forth in the August 2007 Status Report. DOR expects these higher cost levels to continue for the

near future. Attachment 2 sets forth the DOR's current lease cost forecasts through Fiscal 2014.

III. Basis for the Costs Used in DOR's HB 3001 Fiscal Note

The cost projections included in DOR's HB 3001 Fiscal Note were developed in late 2005 and were based on information available at that time. This included confidential income tax returns and public SEC filings for the years through 2004 -- the most recent years available in 2005 -- and published consultant reports covering the period through 2003. DOR reviewed this information with the producers. In addition, we (Econ One) reviewed the DOR's cost projections.

The cost projections used in DOR's HB 3001 Fiscal Note totaled approximately \$2.1 billion for the FY 2008. On a (gross) per-barrel basis, those cost projections averaged \$7.27/bbl.¹ DOR's current volume projections for FY 2008 are approximately 72,000 (79 mbd) lower (725 mbd vs 804 mbd) than they were at the time the Fiscal Note was prepared. Holding total costs constant, this projected drop in volumes would increase the average cost to \$8.04/bbl, an increase of just over 10%.²

The DOR cost projections were used throughout the PPT debate in the spring and summer of 2006 in the analyses it presented to the legislature. In addition, industry presented revenue estimates during the debate that incorporated cost projections in line with the DOR projections.³

We also prepared various revenue projections during the PPT hearings. Those projections fell into two categories: (1) the economics of exploration and development and (2) revenues arising from production in fields included in production forecasts used in DOR's Fiscal Note. Our base cost estimates used in these later estimates were somewhat, though not significantly, higher than the cost estimates used by the DOR.⁴

IV. The Basis for DOR's Current Cost Forecasts

DOR has based its current cost forecasts primarily on the filings submitted by the producer/taxpayers. As has been stated by DOR personnel in testimony, these costs are

¹ The \$7.27/bbl figure represents the average cost per barrel produced. Spread across taxable barrels (assuming an average royalty of approximately 12.9%), it would be \$8.35/bbl.

² The increase in average \$/bbl costs resulting from volume declines may be somewhat smaller than noted above, as a small portion of the total operating costs would be variable with production.

³ See ConocoPhillips presentation on February 27, 2006. While the cost assumptions are not stated in the chart, the revenues for the PPT are in line with the DOR projections, indicating that similar costs were used in the analysis.

⁴ In addition, we presented revenue sensitivities showing varying cost increases over base forecasts. These included a 20% cost increase, an assumption of a tripling of cost inflation (i.e., 7.5% rather than 2.5%) and an increase in capital expenditures by approximately 100% to an annual rate of \$2.5 billion.

not audited, nor have they been adjusted by DOR for potential misstatements or reporting errors.

To our knowledge, DOR has not reviewed any of the supporting information behind the tax filings. Moreover, DOR has not reviewed any of the other information that would regularly be prepared by the field operators detailing their actual and anticipated costs. These would include items such as annual operating budgets, production and drilling plans, regular (e.g., quarterly and annual) expense statements and capital expenditure authorizations (AFEs). This is information that would be shared regularly between working interest owners in each unit.⁵

Without a review of the information underlying the tax filings, or a review of the types of budget and expense reports prepared by the operator of each unit, it is not possible at this time to determine whether the cost increases (relative to the earlier Fiscal Note assumptions) that are reflected in the tax filings to date and the DOR's current cost forecasts will prove to be accurate, or whether they may be adjusted after review.

V. Rising Costs Over the Past Several Years

There is broad consensus among industry analysts that per-barrel operating and capital costs in the U.S. have increased sharply over the past several years. The increase in costs has been higher than general inflation and is driven in large part by higher sustained oil and gas prices relative to expectations of several years ago.

Attachment 3 shows actual ANS West Coast prices over the period January 2000 through September 2007. During this period, ANS prices have increased by approximately \$57/bbl. Moreover, expectations as to long-term crude oil prices have increased considerably just since January 2005. Attachment 4 shows expected price levels as reflected in NYMEX futures trading for oil delivered at the end of 2011. In January 2005 the forward price on the NYMEX was close to \$40/bbl. The forward price rose sharply over the course of the year, ending at close to \$60/bbl. Today, the forward price for delivery at the end of 2011 is about \$80/bbl, which is an increase of \$40/bbl since January 2005.

Expectations for sharply increased, long-term crude oil prices have led companies to spend more money looking for and evaluating prospective properties. In addition, it has led them to spend more money developing costlier reserves from existing properties. This additional demand, which results in large part from an increase in price expectations, has led to increased costs.

VI. Publicly Available Data Regarding Production Cost Increases

Publicly available data reflecting operating and capital costs show increases generally over the past several years, with sharp increases occurring in 2005 and 2006. The timing

⁵ It is our understanding that DOR does not have access to this information at this time.

of these increases is consistent with rapid increases in actual and expected long-term crude oil prices that began in 2005.

Attachment 5 shows an index of upstream capital costs since 2000 presented in a May 8, 2007 release by the consulting firm IHS/CERA. The index is designed to track capital costs associated with oil and gas production world-wide. The IHS/CERA figures show moderate cost inflation (consistent with the general economy) through 2004, then rising quickly, particularly in the 2nd half of 2005 and throughout 2006.

Attachment 6 shows an index of operating costs prepared from lease cost data reported by the Energy Information Administration (EIA) for Lower 48 states.⁶ The EIA operating data shows a cumulative cost increase of 29% in 2006 relative to average cost levels over the 2002 - 2004 period that formed the basis of the earlier DOR forecast.

Attachment 7 shows an index of equipment costs prepared from the same EIA data. This chart shows a relative large increase in costs occurring in 2004, moderating somewhat in 2005 and 2006. On average, 2006 equipment costs reflected in the EIA data were 32% greater than average costs over the 2002 - 2004 period.

Attachment 8 shows an index of daily rental rates for oil drilling rigs in the Lower 48 states prepared using data from the Land Rig Newsletter. Rental rates for oil drilling rigs in the Lower 48 began rising in 2004 and increased sharply in 2005. The rate of increase slowed somewhat in 2006 and has actually declined since 1Q2006. Overall, the index shows an approximate doubling of 2006 daily rig rental rates relative to the 2002 - 2004 period.

None of the data presented in these attachments reflect actual costs in Alaska. Rather, they reflect generalized world-wide costs or costs in the Lower-48 states. These data indicate that the cost of production has risen generally over the course of the past several years. We would expect that the same pressures on production costs outside of Alaska would lead to increased costs in Alaska. And given some of the unique aspects of Alaska's production (isolation, shorter drilling season, number of suppliers available to industry in Alaska during the short-term), combined with the impact of the corrosion repair and "integrity management" work in Alaska, these general cost pressures may impact the State greater than they have elsewhere, at least in the near term.

VII. Production Costs Reported to the SEC and Alaska Specific Costs

Publicly traded oil companies report production costs to the SEC in their annual filings. US companies' data is contained in their form 10-K. Foreign companies, such as BP, report the information in form 20-F. In some cases the costs are broken out separately for Alaska and other areas. Attachments 9 - 12 set forth reported production costs per barrel for ConocoPhillips, BP, ExxonMobil and Chevron. The reported production costs reflect operating expenses and do not include capital investments.

⁶ The EIA does not publish data for Alaska.

ConocoPhillips and BP report their production costs in Alaska separately from production costs elsewhere. These reported figures show generally increasing production costs worldwide over the past 4 years, with higher increases in the U.S. and in Alaska in particular. Alaska cost increases reported by BP were much greater than those reported by ConocoPhillips over the last 2 years.

ConocoPhillips' publicly reported production costs over the period 2003 - 2006 for equity production in Alaska and the Lower 48 states are set forth in Attachment 9. The ConocoPhillips' data shows Alaska production costs of approximately \$3.50 per barrel between 2003 and 2005. These are similar to the operating costs used by the DOR in their earlier forecasting.

Consistent with the cost and price data presented above, the ConocoPhillips' reported costs began to rise in 2005, with a sharp (63%) increase in 2006 to approximately \$6.40/bbl. ConocoPhillips' production costs for the Lower 48 states shows a much more moderate rate of increase over the past 4 years than do their Alaska costs.

BP's publicly reported production costs over the same period for equity production in Alaska, the United States and the rest of the world are set forth in Attachment 10. BP's reported figures for Alaska are in the same general range as ConocoPhillips' costs for 2003 and 2004 (approximately \$3.50 per barrel), then rise in 2005 by 38%, with a further sharp (81%) increase to over \$9.00/bbl in 2006.

ExxonMobil's reported costs are shown in Attachment 11. Unlike the other 2 large producers, ExxonMobil does not break out Alaska in its public filings. ExxonMobil's reported figures show increasing production costs over the 2002 - 2006 period higher worldwide, with a greater increase in the US, particularly in 2006.

Attachment 12 shows production costs reported by Chevron for the 2002 - 2006 period. Chevron's costs show increases generally over the period, with larger increases in the US beginning in 2005.

VIII. Information on Corrosion-Related Costs

DOR personnel stated that they did not know the amount that has been claimed for costs related to corrosion repair work on the North Slope. The level of cost reporting contained in the PPT filings does not provide detail regarding the nature of underlying costs. And as discussed above, these tax filings largely form the basis for DOR's cost projections going forward.

One way to attempt to determine the extent of corrosion related costs claimed and included in the tax filings would be to examine and compare the tax data across taxpayers and units, comparing costs claimed for Prudhoe Bay and by BP with costs claimed by other taxpayers and for other areas. While DOR has certainly done this, they stated that they could not share any data or analysis with us due to stated tax-payer confidentiality issues.

BP has stated publicly that it will spend \$260 million to replace the oil transit lines (OTLs) at Prudhoe Bay. Assuming these costs are all spent during 2006 and 2007, they would represent a little more than a \$1/bbl cost spread across taxable barrels at Prudhoe Bay for those two years.

In addition to the \$260 million OTL replacement cost figure, BP reported in its 2006 form 20-F that it planned to spend over \$550 million during 2007 and 2008 "net" on "integrity management" in Alaska.⁷

There are several questions with respect to this figure and how it relates to the corrosion issues. First, BP's filings do not define what is included in "integrity management." However, the statement would appear to be directed to efforts to insure the "integrity" of facilities at Alaska in an effort to prevent future spills or shutdowns. Second, BP's reports do not specify whether these would be operating or capital expenses. Third, it is unclear whether the \$550 million figure is all that is anticipated with respect to the integrity management issues, or whether BP has just reported anticipated costs for a two-year period. Fourth, it is unclear whether the \$550 million refers to expenses born solely by BP in its capacity as working interest owner, or whether these reflect the gross amount that BP as operator will pay on behalf of itself and the other working interest owners at Prudhoe Bay. If these expenses reflect BP's net working interest share, then the total integrity management expenditures over the 2007 - 2008 period could be far greater than \$550 million. Finally, aside from this statement, BP's filings do not separately list expenditure amounts related to "integrity management" issues prior to 2007. Accordingly, the publicly available data do not allow us to determine exactly how much of the \$550 million spending represents an increase in spending levels for this expense category relative to prior years.

Whether and to what extent corrosion-related costs are reported as a part of taxpayers' PPT deductions, the impact of these events likely has had some effect on increasing overall production costs on the North Slope for non-corrosion-related production services. As discussed above, increasing oil prices overall have put pressure on costs. The added pressure to deal with the corrosion repair and integrity management issues, particularly in a short time period, adds to the general cost pressure brought about by rising crude oil price expectations.

IX. Some Final Thoughts on Cost Increases and the PPT

⁷ BP's 2006 form 20-F, page 19 states, "In response to the recent corrosion discoveries, BP has decided to replace the main oil transit lines (16 miles) in both the Eastern and Western Operating Areas of Prudhoe Bay. In addition, BP plans to spend over \$550 million (net) over the next two years on integrity management in Alaska."

The PPT system, through the deduction of costs and capital credits, was designed to encourage capital investment and increased production in Alaska over the long run. Accordingly, the fact that costs have risen relative to expectations, particularly capital-related costs, should not be viewed in and of itself as a problem. Indeed, increased capital spending is one of the policy objectives of the PPT system.

However, it would seem doubtful that the entirety, or even the majority, of the cost increases reflected in the producers' tax filings to date relative to the projections used in the earlier Fiscal Note are the result of potential stimulative effects of the PPT system.

At the outset of this project we had sought to obtain data from the DOR as to costs filed by category (i.e., capital and operating) at different fields. Examination of that data might provide an indication as to where (geographically) the cost increases relative to forecast were coming from. In addition, such an examination, along with information regarding drilling activity, might provide insight into the question of whether some of the increased costs could be explained by increased exploration activity and/or development activity in certain areas, which are policy objectives of the tax system.

As discussed above, DOR personnel have maintained that cost information by taxpayer and even aggregated cost across taxpayers by field or unit, is considered as taxpayer confidential and could not be made available. Accordingly, we were not able to undertake this analysis as initially hoped.

Based on our discussions with DOR personnel and the data reviewed we can draw the following conclusions with respect to the cost increases in DOR's model in this time.

- The DOR's forecasts are based largely on unaudited taxpayer returns under the PPT tax. Those costs may be reduced after review and audit.
- An increase in costs for Alaska production is consistent with the cost patterns observed generally in the industry during the past several years. Costs began to increase sharply beginning generally in 2005.
- Forecast costs used in DOR's Fiscal Note to HB 3001 appear to be in line with publicly (SEC) reported information specific to Alaska during the period 2002 through 2005.
- Capital cost forecasts used by the DOR in the HB 3001 Fiscal Note are in line with historical capital spending levels on the North Slope between 2002 and 2005.
- Repair costs for corrosion related work and integrity management on the North Slope likely add costs for non-corrosion related costs in Alaska generally.

- The increases in costs filed with the SEC for Alaska relative to the Lower 48 and elsewhere reflect in part, expenses associated with corrosion repair and “integrity management” efforts in Alaska.
- The size of the cost increases, as reflected in the DOR’s forecasts, suggests that corrosion-related expenses and/or higher anticipated “integrity management” expenses are likely included in the tax filings, and as a result, included as a part of the cost forecasts.
- A proper determination of the reasons (appropriate or inappropriate) underlying the cost increases will require examination of the data underlying producer/taxpayer returns and claims under the PPT period. The examination should include review of unit-by-unit cost information both during the PPT period (i.e., from April 2006 forward) and during the several years prior to the implementation of the PPT.
- Costs have increased in recent years with unexpected increases in expectations of future crude oil prices. In the event that price expectations increase further costs may further increase. The level of increase is likely to be mitigated over the longer run with new entry (i.e., increased supply) for production-related services.
- Likewise, to the extent that long-run price expectations fall significantly (say down to \$40/bbl), we can expect to see downward pressure on costs over the long term.
- DOR did not include a cost/price sensitivity in its HP 3001 Fiscal Note or in its PPT Status Report. Its current forecast adjusts costs up or down when expected price levels rise above or fall below \$60/bbl, respectively. While these relationships are difficult to estimate with precision given the information available, in our view, this type of sensitivity is a good addition to the forecasting process.

Attachment 1

Petroleum Profits Tax (PPT)
Implementation Status Report

Alaska Department of Revenue
August 3, 2007

PPT IMPLEMENTATION STATUS REPORT

I. Purpose of the Report and Conclusions:

In August 2006, the Alaska Legislature passed HB 3001 containing a new oil and gas production tax system called the Petroleum Profits Tax (PPT). The new profits-based tax replaced the previous production tax based on gross value, generally referred to as the "Economic Limit Factor" (ELF) tax system. Debate and passage of HB 3001 was contentious, with questions raised on the propriety of a profits-based tax and on the appropriate tax rate. The controversy escalated earlier this year with the handing down of federal indictments against several legislators that centered on potential corruption involving the PPT deliberations and votes.

The Governor tasked the Commissioner of Revenue with evaluating whether the PPT was meeting expectations with respect to state revenues and industry's reinvestment in Alaska. The Commissioner of Revenue formed a Production Tax Team, staffed with members from the Department of Revenue, Division of Tax and the Department of Natural Resources, Division of Oil and Gas to review various aspects of PPT implementation. Based on the information provided by the Production Tax Team, the initial conclusions of the Department of Revenue are:

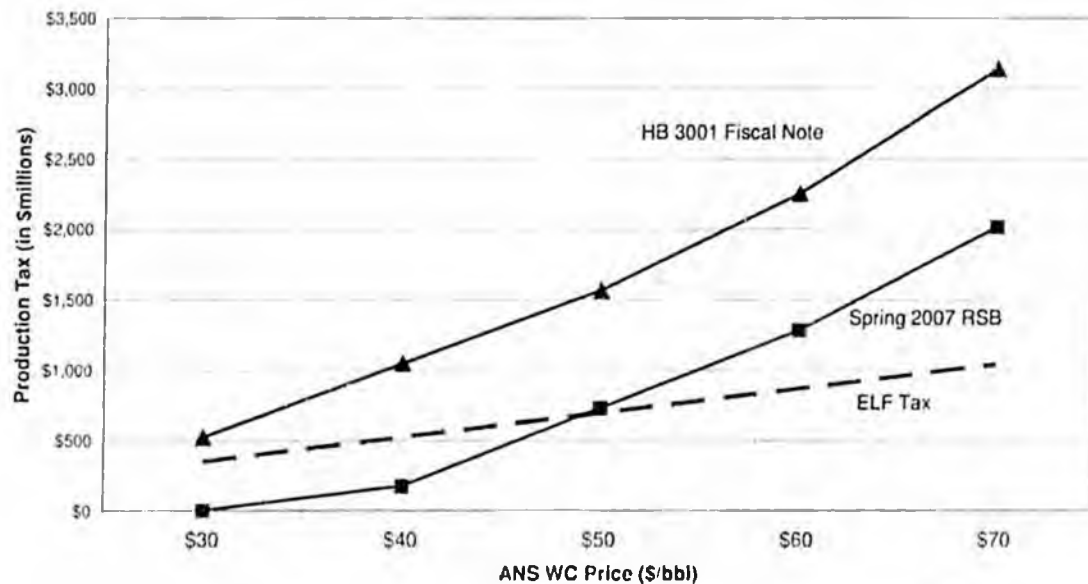
- 1) At current prices, the state is collecting more production tax revenues under PPT than it would have under the ELF system. However, those revenues are falling far short of what was expected when PPT was passed.
- 2) Operating and capital costs are substantially higher than were forecasted in the PPT fiscal note provided to the legislature.
- 3) The value of PPT credits may not be fully realized for exploration companies new to Alaska, given the small market for resale among "producers."
- 4) The crossover oil price point where the state receives more revenue under the PPT than under the ELF system has moved from the \$26/barrel predicted in the PPT fiscal note to \$48/barrel.
- 5) The activation of the progressive surcharge has shifted from a market price of \$55 to over \$60 a barrel.
- 6) DOR faces significant challenges in implementing the PPT as currently structured.

II. Discussion:

1) Production tax revenues are falling far short of expectations. The following graph shows the differences in modeling results for FY 2008 production tax revenues; this graph compares initial modeling for FY 2008¹, as prepared for the House Bill 3001 (PPT) fiscal note [SCS HB3001(NGD)], with current modeling, as prepared for the *Spring 2007 Revenue Sources Book*, and with the tax revenue that would have been generated under the ELF system. The tax revenue expectations for FY 2008 are significantly lower than the revenue forecasted when the fiscal note was drafted. This is primarily due to the significantly higher costs being reported as compared to what was estimated in the fiscal note, as noted below.

In FY 2008, based on forecasted price and production levels, the PPT is expected to generate about \$250 million over that which would have been generated under the ELF system. However, this is more than \$800 million less than what was predicted in the PPT fiscal note.

FY 2008 Production Tax Estimates: HB 3001 (24th Legislature) Fiscal Note and Spring 2007 Revenue Sources Book PPT Forecasts; and ELF Tax



Note: All revenue estimates are based on most current taxpayer submitted expenditure forecasts and do not reflect any changes in spending due to increases or decreases in oil price.

¹ Because of the unexpected disruptions to revenues and costs caused by the gathering line failures in the Prudhoe Bay Unit in FY 2007, the Department is using FY 2008 as the comparison year to eliminate one-time aberrations. In addition, the HB 3001 Fiscal Note and ELF Tax models have been adjusted to reflect current production estimates.

2) Operating and capital costs are substantially higher than were forecasted in the PPT fiscal note. The substantial and unanticipated increase in costs is the primary reason revenues are falling short of expectations. Throughout the latter half of 2004 and 2005, DOR officials gathered information from confidential tax documents, annual reports, private consultant analyses, and the industry about the costs of producing petroleum on the North Slope. DOR modeled the PPT revenue forecasts using these cost data and the results of this modeling were provided to the legislature to aid their consideration of the PPT.

Based on the cost data received by the Department for 2006 and 2007 since passage of PPT, the Department has increased by almost 100% taxpayer operating and capital cost estimates for FY 2008 in its Spring 2007 Revenue Source Book revenue projections. In discussions with taxpayers, DOR has been told that these higher costs levels for 2006 and 2007 are not aberrations caused by unique events, such as the Prudhoe Bay shutdown, and that we should anticipate costs remaining at these levels for the foreseeable future.

**North Slope Production and Costs FY 2008,
per HB 3001 Fiscal Note and Spring 2007 Forecast**

	HB 3001 Fiscal Note	Spring 2007 Forecast
FY 2008		
Production (barrels per day)	802,000	764,000
Costs		
Operating costs (\$millions)	\$1,076	\$2,160
Capital costs (\$millions)	\$1,052	\$1,900
Total Costs	<u>\$2,128</u>	<u>\$4,060</u>
Total Costs per Barrel	\$7.27	\$14.56
Operating costs per barrel	\$3.68	\$7.75
Capital costs per barrel	\$3.59	\$6.81

High oil and gas prices since 2005 are frequently cited as the cause of these cost increases. Projects around the world that were once only marginally economic, are now considered very viable, and are now placing increased demands on limited supplies of engineering, procurement and construction services and on raw construction materials. The Upstream Capital Costs Index, developed by Cambridge Energy Research Associates (CERA), shows that costs for oil and gas production equipment, facilities, construction materials and personnel have increased 53% since 2005. CERA expects cost escalation to continue through 2007, although at a slower pace. Fluor Corporation estimates that prices for fabricated structural steel have increased 60-70% from 2003 to 2006, and that delivery times for these materials increased by 18-20 weeks from their previous levels. The same company reports that prices for seamless and welded pipe used in petroleum production have increased 80-160% from 2003 to 2006, and expects increases of another 15-50% by 2009.

It is too early to tell whether all of the costs reported under PPT thus far are properly deductible. Also, it is too early to know whether the increase in reported industry spending in the state will result in increased future production, or whether the increase in spending can be attributed to changed behavior as a result of the incentives included in PPT. What we do know is that the costs used in the modeling for the PPT fiscal note have proven inaccurate.

3) The value of PPT credits may not be fully realized for exploration companies new to Alaska given the small market for resale among "producers."

Under PPT, tax credits earned by investors and explorers may be transferred and sold to other taxpayers who have a production tax liability. Companies that have been issued credit certificates above and beyond the \$25 million that can be refunded by the state would presumably sell their certificates to the highest bidder. In the first year that the PPT has been in place, however, companies holding credit certificates report that there have been few buyers for the certificates, and that those offering to buy them are doing so at large discounts.

4) The oil price crossover point where the state receives more revenue under the PPT than under the prior ELF system has moved from \$26/barrel to \$48/barrel.

The ELF system "crossover point"—that is, the Alaska North Slope - West Coast (ANS WC) oil price whereby the PPT generates more revenue than the ELF system—was the focus of some attention during the 2006 legislative session. Primarily due to the increase in the cost estimate, the currently estimated crossover point is substantially higher than was projected in 2006.

5) The activation of the progressive surcharge has shifted from a market price of \$55 to \$60-63 a barrel. Because the surcharge is not activated until the taxpayer's net income per barrel exceeds \$40, higher costs have depressed taxpayer net income, thus delaying the price at which the surcharge kicks in. In addition, as production declines, the price at which the progressive surcharge is activated will move higher as costs are spread over fewer barrels. Although the level differs for each individual taxpayer, the North Slope average progressivity trigger is now estimated to be somewhere between \$60 and \$63 per barrel.

6) DOR faces significant challenges in administering the PPT as currently structured.

a) Regulations- The second phase of PPT regulations has been delayed as a result of the challenge of accurately describing the allowed and disallowed lease expenditure deductions.

b) Revenue Forecasts- The Department has been severely hampered in its ability to provide the administration and the legislature with accurate revenue forecasts because the department lacks future capital and operating expenditure information. The Department is in the process of rectifying this problem by requiring operators to provide forward-looking cost data, when and as provided to the unit working interest owners.

Statutory changes may be required to fortify and focus these requests for unit cost information.

c) Audits- With the passage of PPT, the department was authorized to hire eight auditors and one tax technician to assist with the additional audit requirements of the new tax structure. To date, the department has successfully filled the three most senior auditor positions, and has reduced the skills requirements for the remaining junior level auditor positions in light of the challenges of matching competitive pay with the more senior level skill sets.

The complexity of auditing production tax has increased several fold under the PPT, and the PPT increased the number of determinations an auditor must make. The provisions in the PPT which are intended to simplify and streamline these determinations through reliance upon unit owners' auditing of unit operators may assist this process, but we have not yet been through an audit cycle to assess the efficacy of this approach.

III. Conclusion

The state's experience with PPT puts a spotlight on the risks associated with a net profit-based tax system. The new system introduced the added variable of costs into the oil revenue equation. While it is a risk that is inherent in the decision to approve a net profit-based tax, the question is whether the magnitude of the risk was fully understood by the legislature given the information provided to them. While costs would be expected to increase, the dramatic difference between what was predicted and what has actually been experienced brings into question whether the legislature made its decisions based upon appropriate information.

Another aspect of PPT, the tax credits given for capital expenditures, has been significantly reduced in value due to the lack of an efficient market for those new exploration companies looking to sell their credits to those who have current production. This deficiency is particularly troubling because these new exploration companies are the ones that provide the state with the greatest opportunity to encourage new production that might not otherwise occur.

Clearly, there are aspects to PPT that should be re-examined by the legislature. In particular, the legislature should reassess whether the state is getting its fair share of oil and gas revenues, and whether the credits are designed optimally to provide the maximum impact on the state's goal of encouraging investment that leads to more oil and gas production.

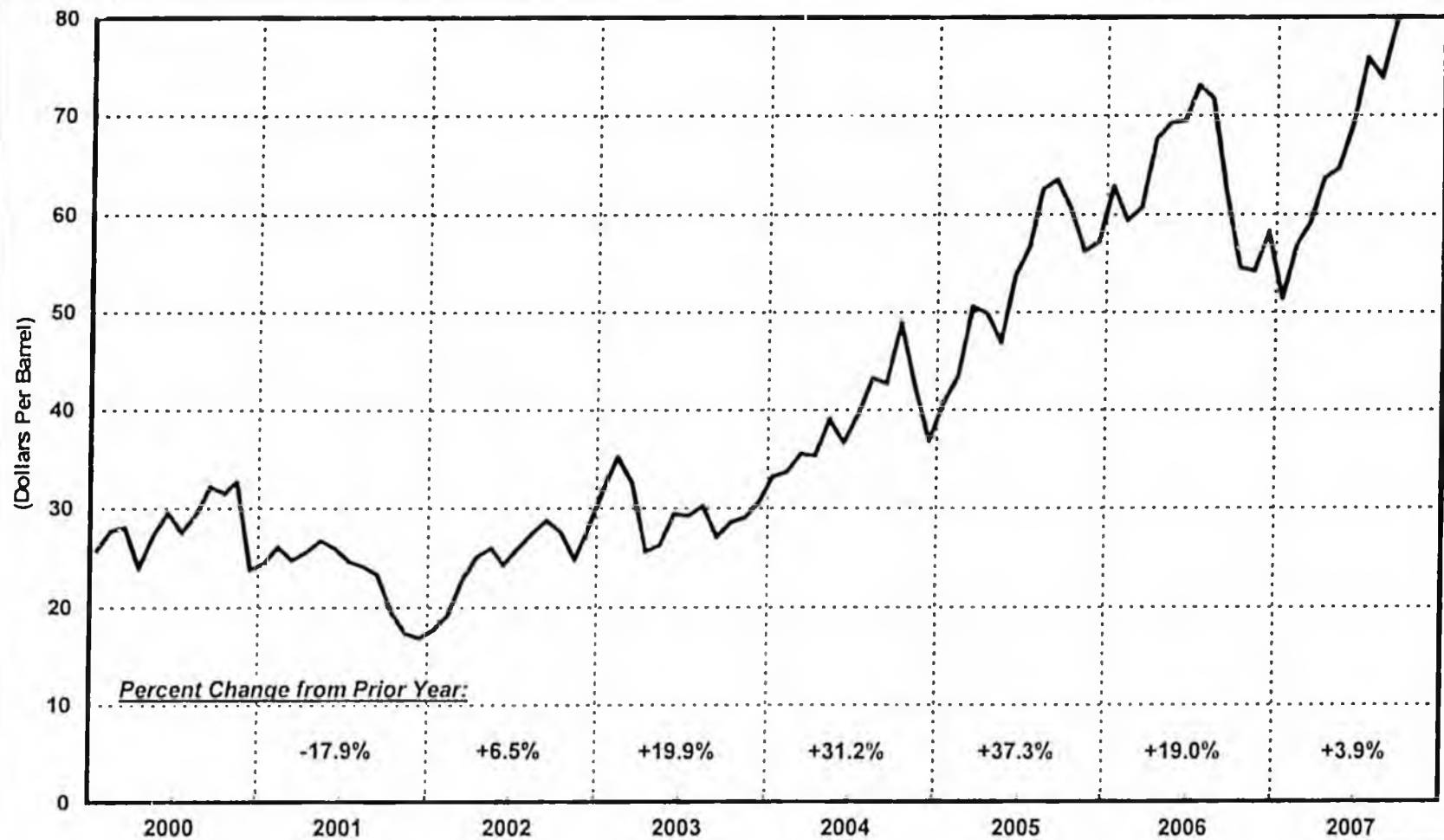
Attachment 2

**Summary of Cost Assumptions in
Fiscal Note to HB 2001 (ACES)
FY 2008 - FY 2014**

<u>FY</u>	<u>Operating Costs</u>	<u>Capital Costs</u>	<u>Operating and Capital Costs</u>
	(Million Dollars)		
	(1)	(2)	(1) + (2) (3)
2008	\$2,146	\$2,187	\$4,333
2009	2,286	1,932	4,218
2010	2,375	2,024	4,399
2011	2,464	1,950	4,414
2012	2,572	2,028	4,599
2013	2,638	2,021	4,660
2014	2,712	2,360	5,072

Attachment 3

Platt's ANS Crude Oil Price January 2000 – September 2007

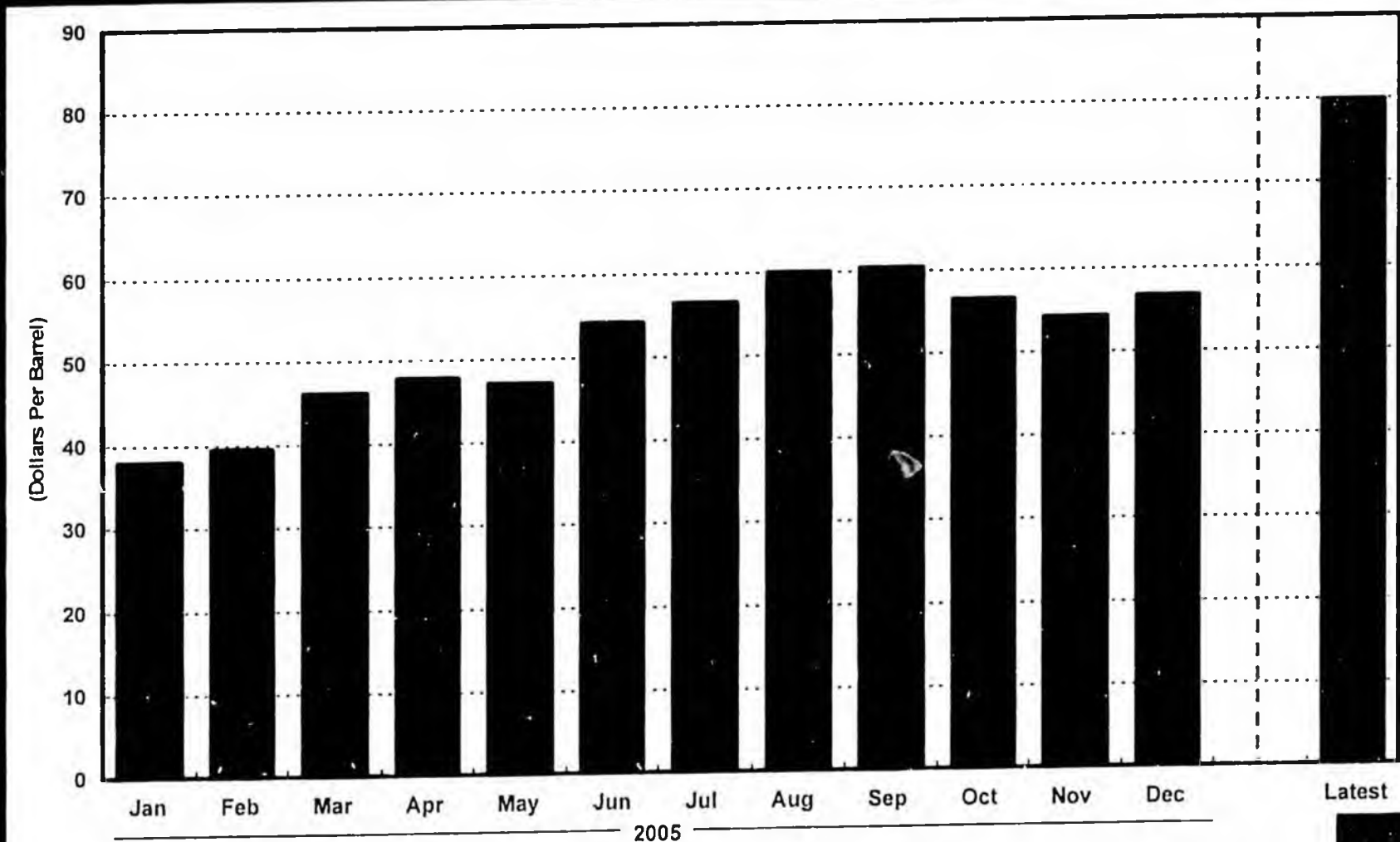


Source: Platt's.

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Attachment 4

NYMEX Futures Price for December 2011 Delivery January - December 2005, Latest Quotes

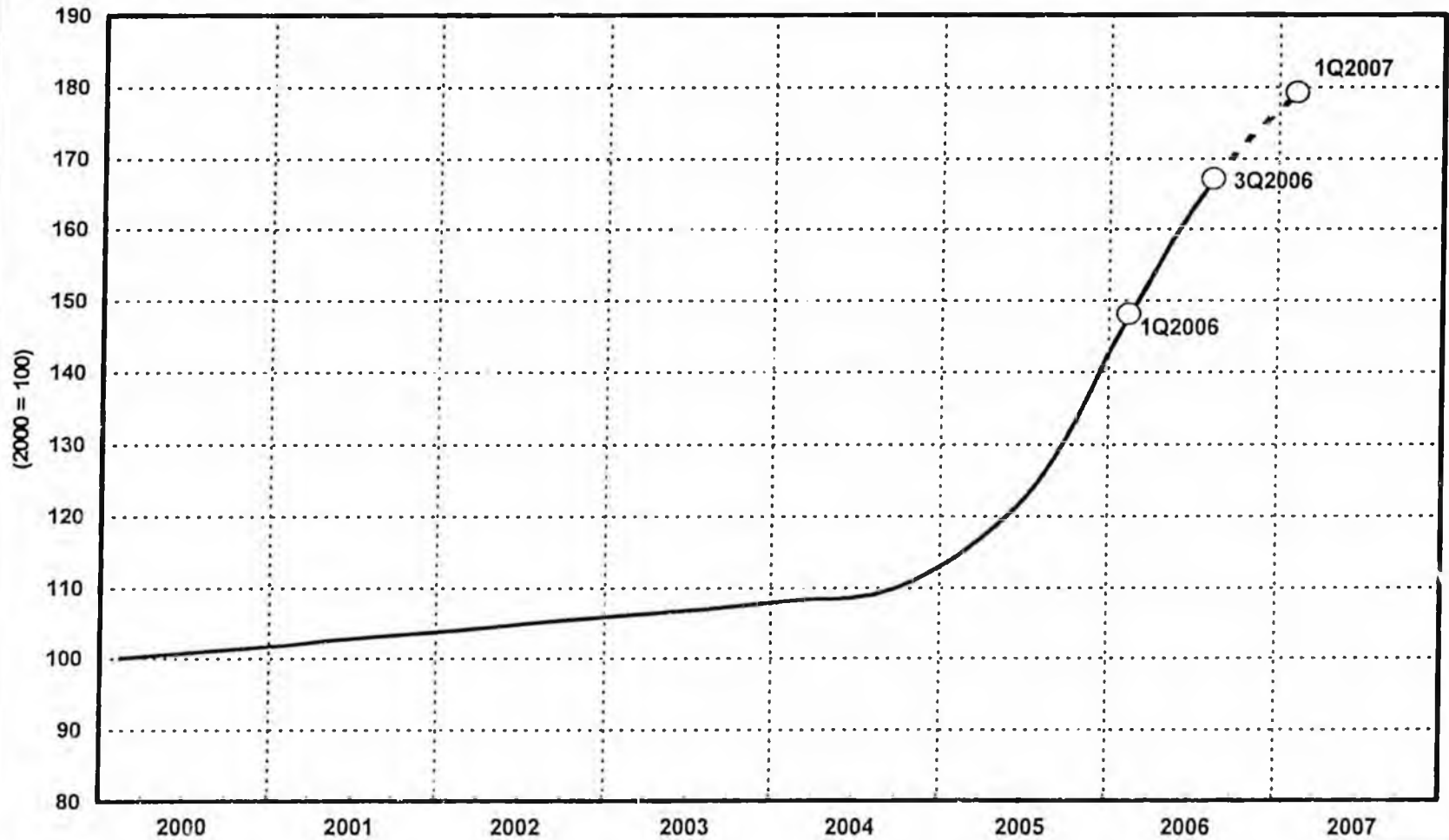


Source: NYMEX.

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Attachment 5

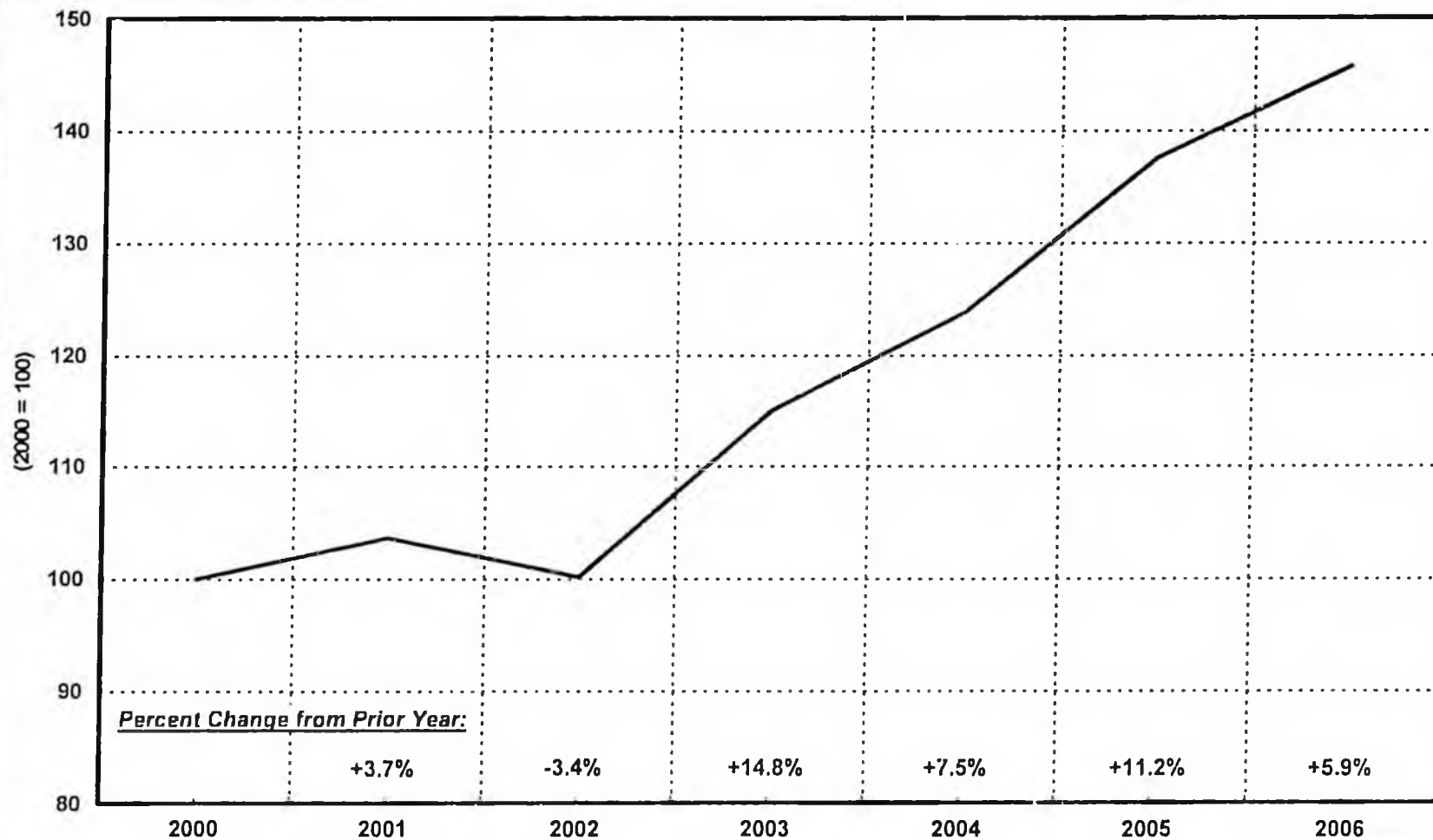
IHS/CERA Upstream Capital Cost Index 1Q2000 - 1Q2007



Source: Based on Cambridge Energy Research Associates May 8, 2007 Press Release.

Attachment 6

Average* Operating Costs for 10-Well Oil Lease Index 2000 - 2006

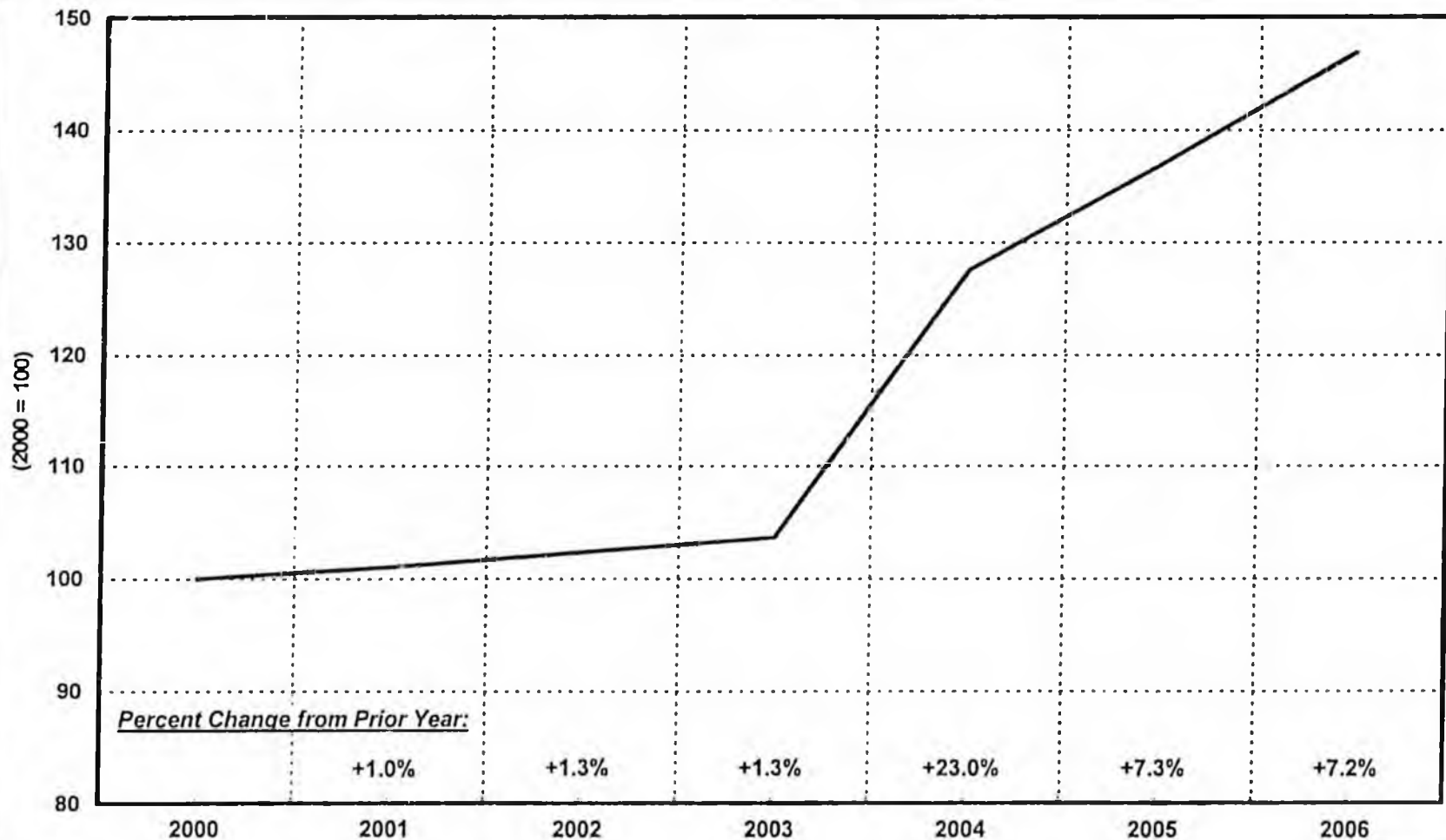


* Average of California, Oklahoma, South Louisiana, South Texas, West Texas, and Rocky Mountains.

Source: EIA.

Attachment 7

Average* Equipment Costs for 10-Well Oil Lease Index 2000 - 2006



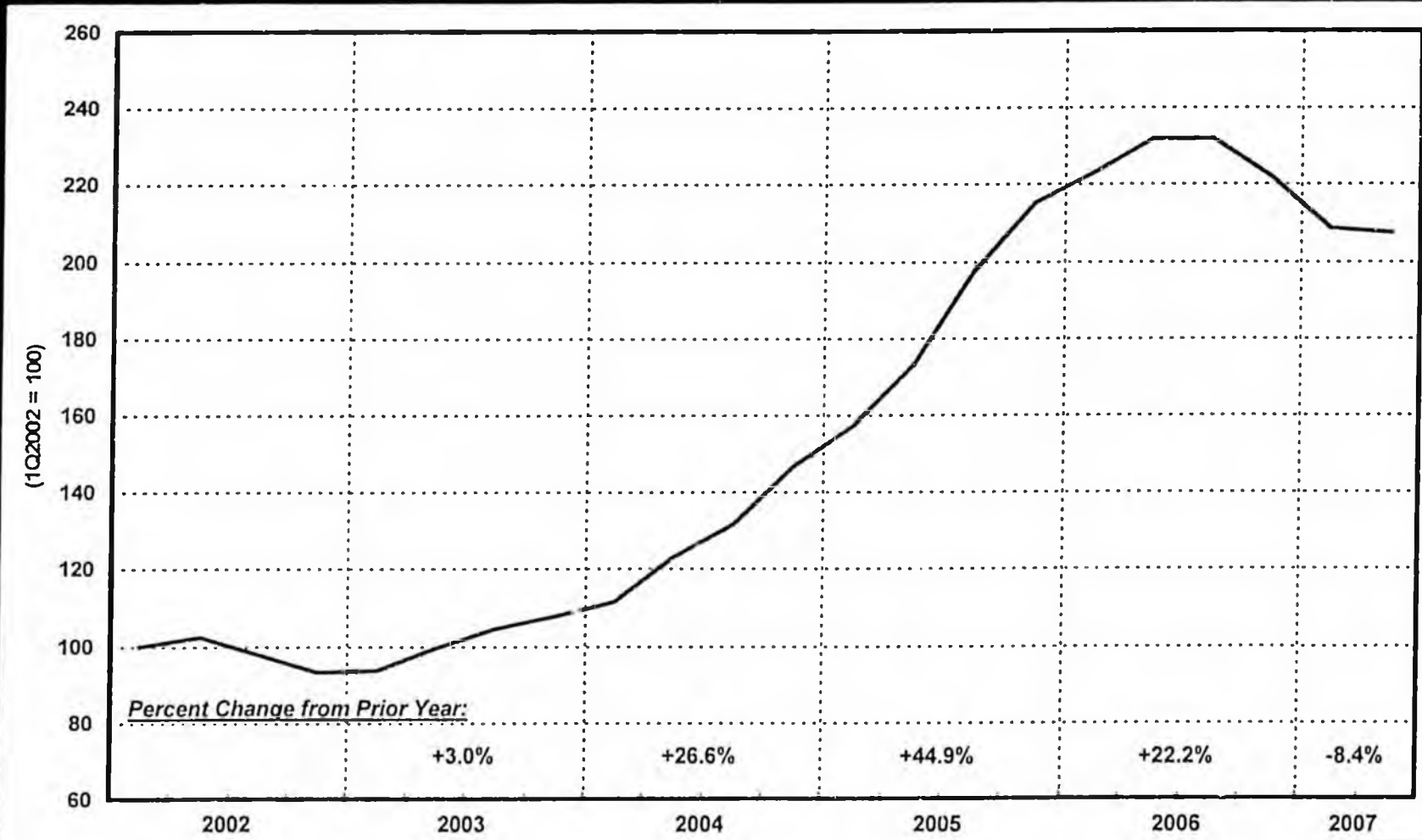
* Average of California, Oklahoma, North Louisiana, South Texas, West Texas, and Rocky Mountains.

Source: EIA.



Attachment 8

Average* Oil Drilling Rig Daily Rates Index 1Q2002 - 2Q2007



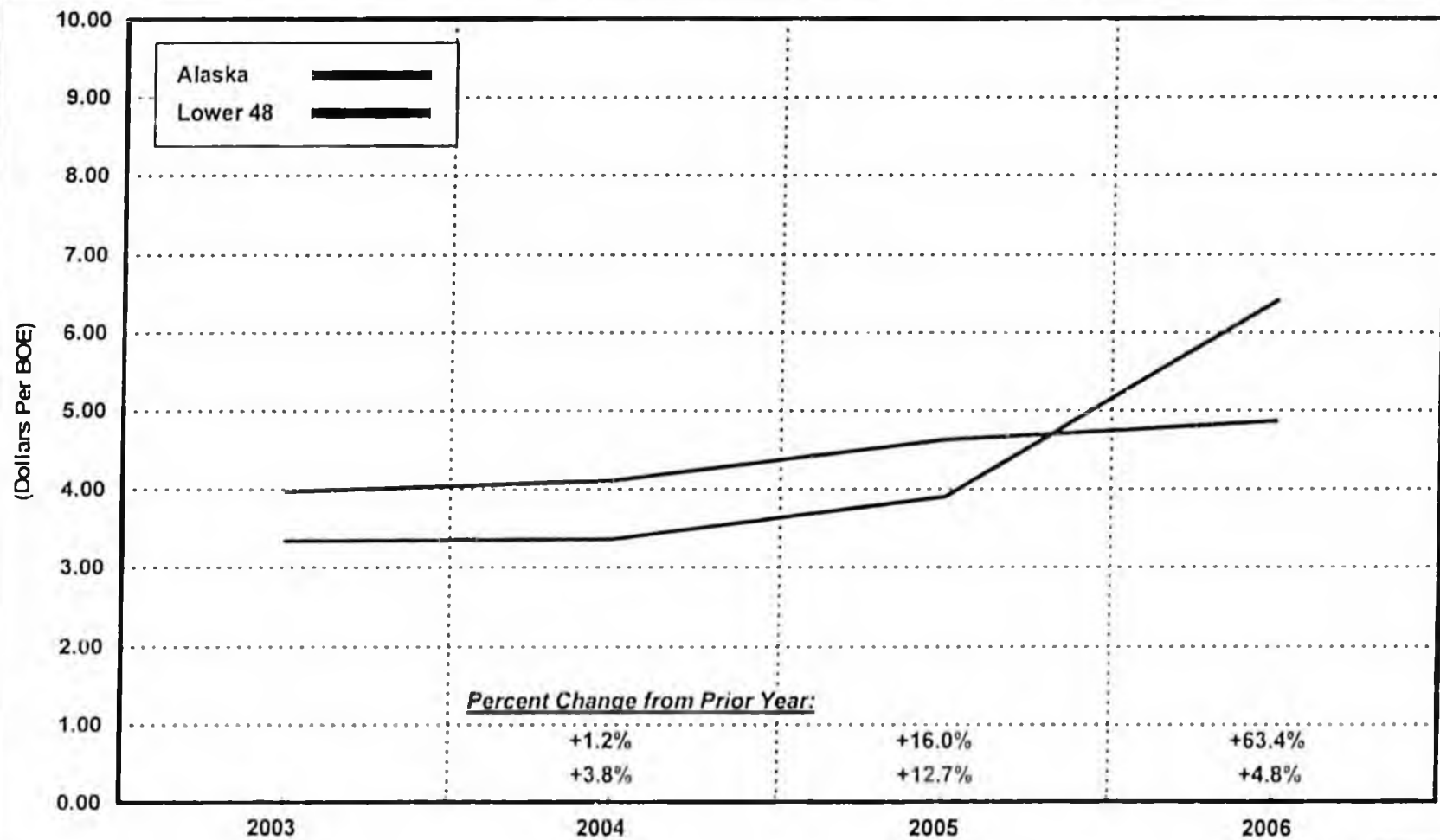
* Average of Mid-Continent, ArkLaTex, Gulf Coast, Permian Basin, Rocky Mountains, and South Texas.

Source: Land Rig Newsletter.



Attachment 9

ConocoPhillips Reported Production Costs Per BOE 2003 - 2006

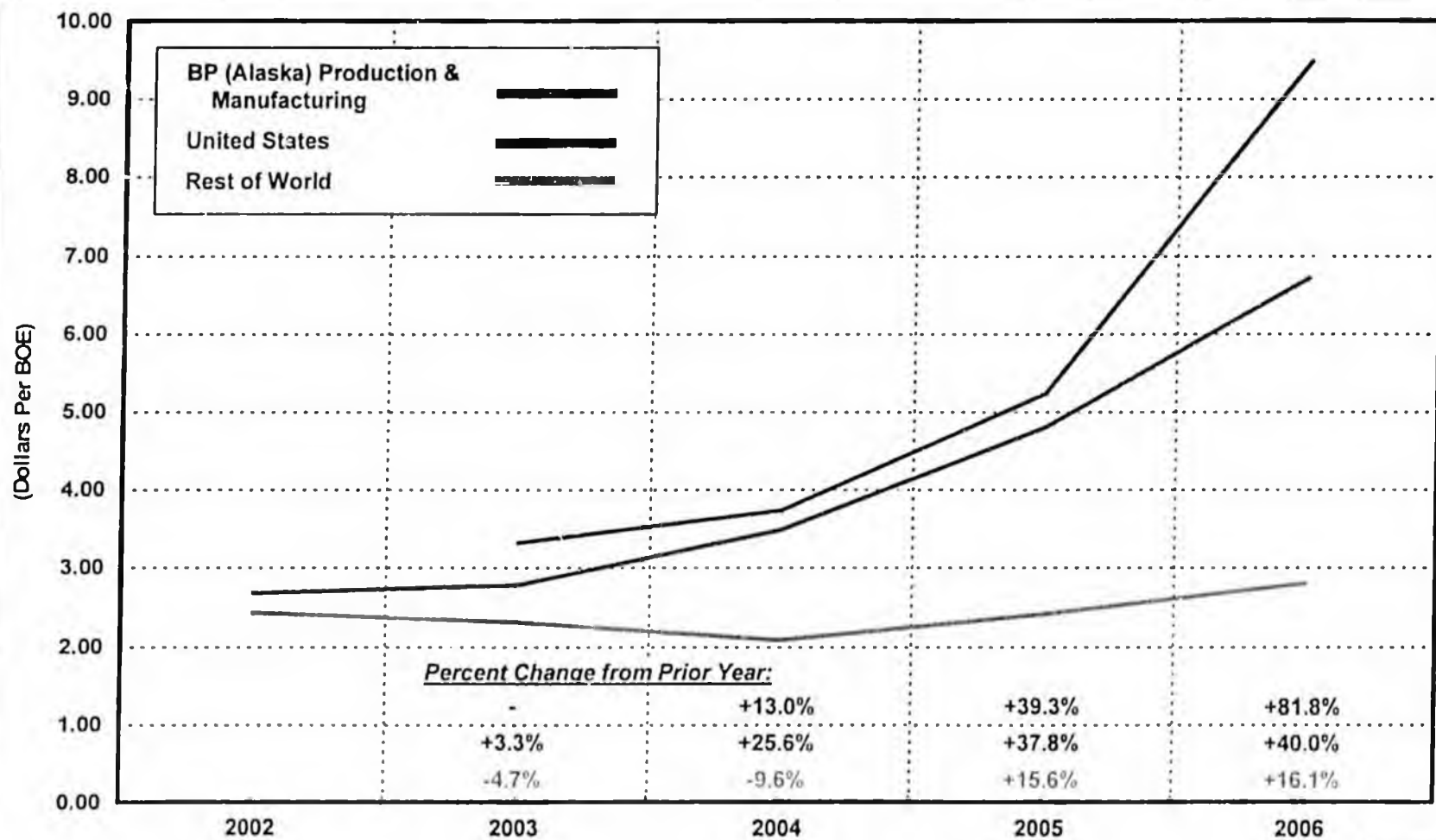


Source: ConocoPhillips 10-K filings.



Attachment 10

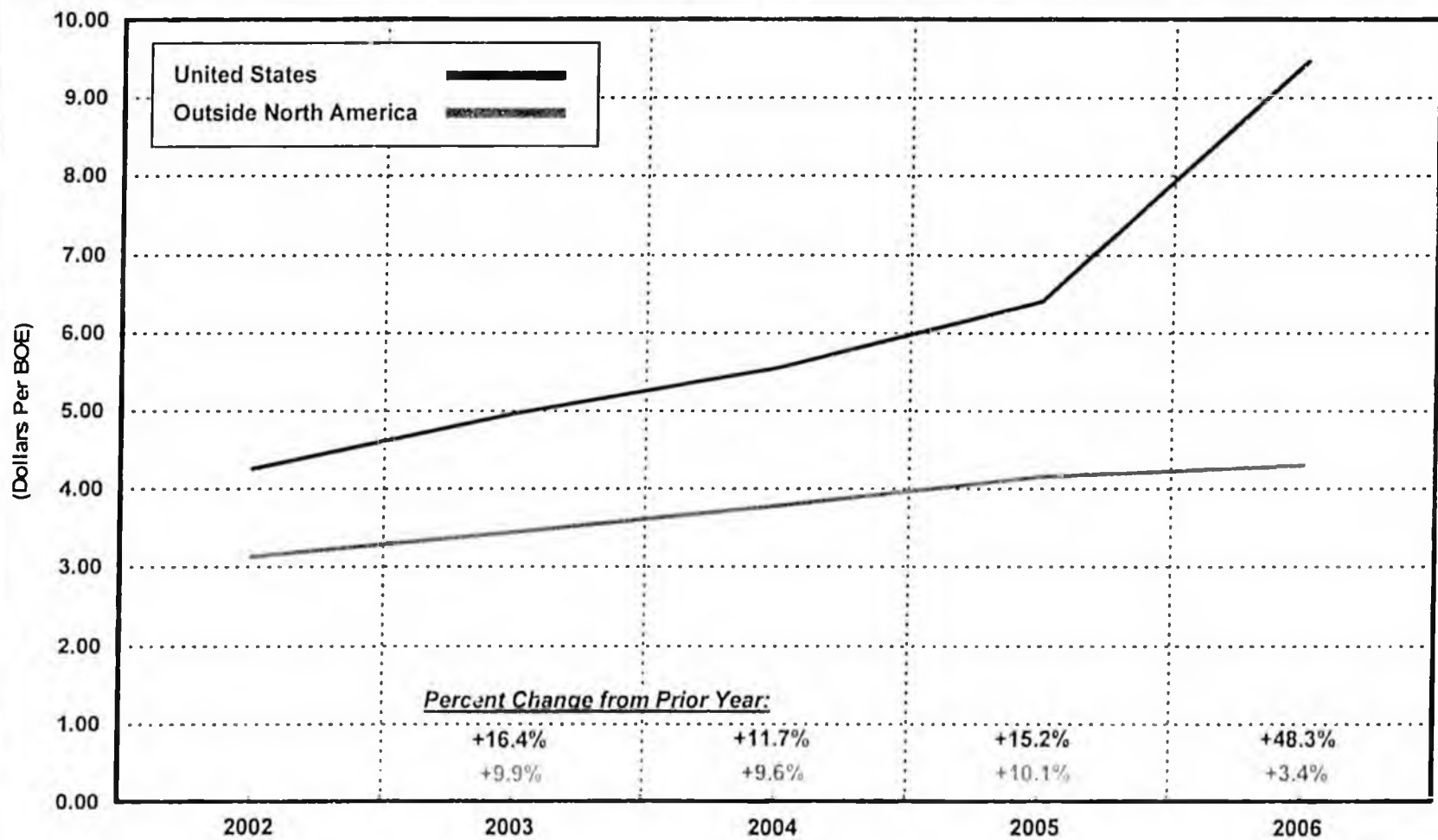
BP Reported Production Costs Per BOE 2002 - 2006



Source: BP Financial and Operating Information, 2002-2006.

Attachment 11

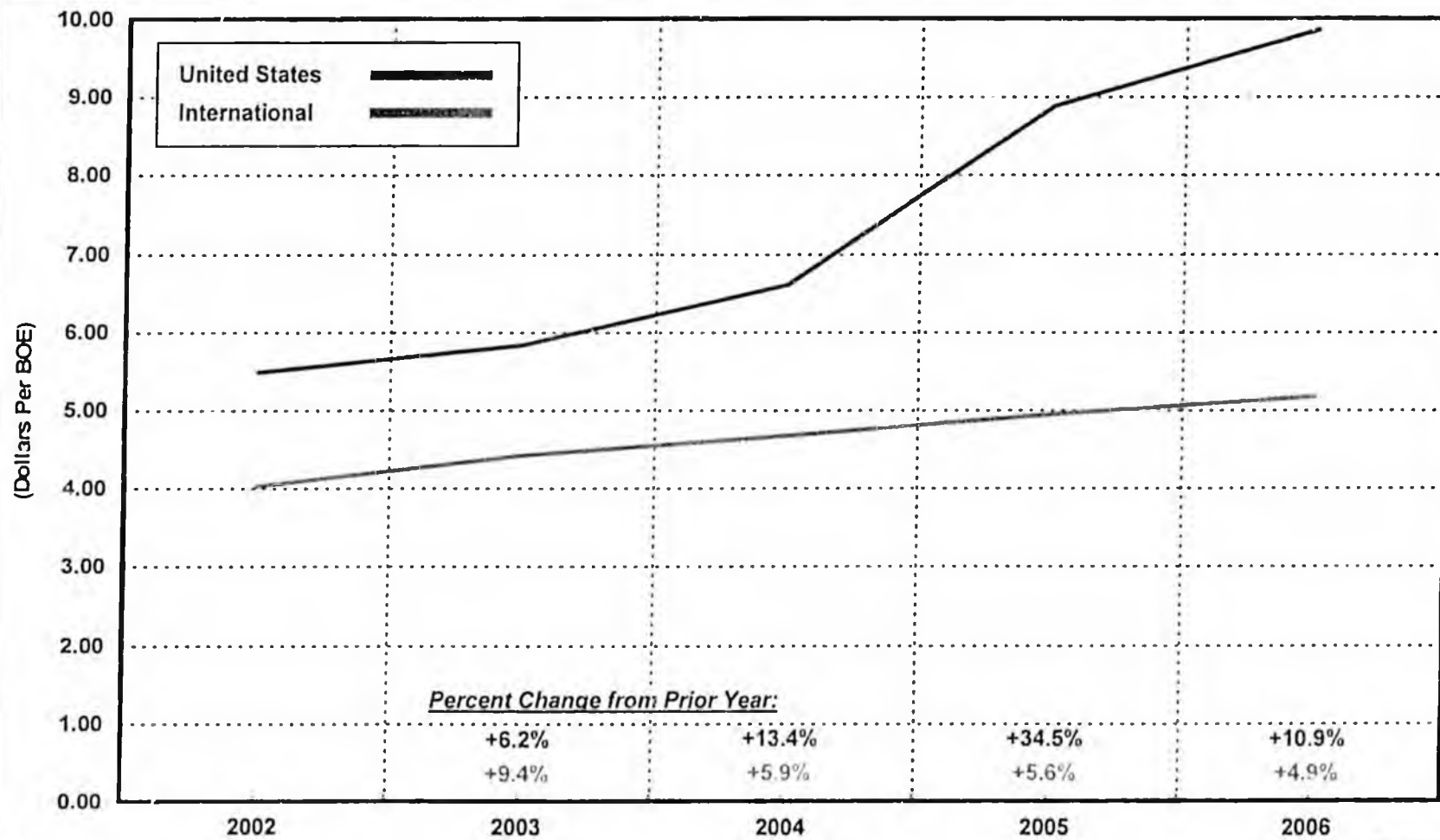
ExxonMobil Reported Production Costs Per BOE 2002 - 2006



Source: ExxonMobil Financial and Operating Review, 2006.

Attachment 12

Chevron Reported Production Costs Per BOE 2002 - 2006



Source: Chevron 10-K filings.

HB

20001

(FILE 3)

HFIN

FILE

SECTIONAL ANALYSIS

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Base Rate AS 43.55.011 (e) & (g) Bill Sections 15 & 17					
Base Tax Rate		25%		25%	
Progressivity AS 43.55.011(g) & (h) Bill Sections 17,18					
\$/bbl Starting point	\$40 net	\$30 net	\$50 gross	\$30,40,50,60 net	
Tax/\$ of Price Index	0.25%	0.20%	0.25%	.2,.3,.4,.5%	
Average Value over	month	year	month	month	
Applied to	net	net	net	gross	
Cap		25% of net	25% of gross	none	
Gross Value Floor AS 43.55.011(f) Bill Section 15, 16, 31-36, & 41-42					
Base		Prudhoe; Kuparuk			
Rate		10%			
Credits further reduce floor tax?		No			
Investment Credits AS 43.55.023 Bill Section 26-28, 38-44 & 63					
Investment Credits	Taken in year of investment	1/2 in each of two years	Taken in year of investment	Taken in year of investment	
Loss Carry Forward Credits		25%		rate in (e) (25%)	
Transitional Investment Credits	Yes	No	3 years of investment instead of 5	3 years of investment instead of 5	
Exploration Credits AS 43.55.025 Bill Section 36 - 44					
Rates		20; 40%		30;40%	
G&A Costs		bad acts I		bad acts I	
DNR approval required?		Always		Always	
Confidentiality of well data		2 years		2 years	
Pre-existing well		Two consecutive drilling seasons		Two consecutive drilling seasons	
"DNR TIE" Credits for pre 2003 seismic work?		5%		5%	

Summary Comparison between Various House Approaches to Production Tax

Issue Current Law HB 2001 (ACES) House O&G House Resources House Finance

State Purchase of Credits		<i>AS 43.55.023(f) & (g)</i>	<i>Bill Section 45 (AS 43.55.028)</i>	
Paid from:	"appropriations made by law"	oil and gas credit fund, funded from production taxes	"appropriations made by law"	oil and gas credit fund, funded from production taxes
Annual dollar cap per taxpayer?	\$25 million	none	\$25 million	Yes (however ARM unlimited)
ARM Board Purchases?	n/a	n/a	n/a	yes

Allowable Lease Expenditures		<i>AS 43.55.165</i>	<i>Bill Sections 52-64</i>	
Use producer audits of operators?	Explicit	Explicit repealed; Implicit	Explicit	Explicit repealed; Implicit
Disallow bad acts II?	yes	add violation of law, lease or license	add violation of law, lease or license	add violation of law, [inc Clean Water Act] lease or license
Dispute resolution	except with state	except with state	except with state	no, other disallowances
DR&R Allowed?	Allocated	No	No	No
"Corrosion" Issue		\$0.30 + unscheduled events disallowed	\$0.30 + unscheduled events disallowed	
Field Topping Plants allowed?	Yes	No	No	No
Off Lease allowed	yes; other tests	yes; other tests	yes; other tests	No (also in-state)

Information		<i>AS 43.05.230 and royalty statutes</i>	<i>Bill Sections 2-9,11-13, 49 & 61</i>	
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	information "necessary to forecast ... revenues under AS 43.55".	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.
Disclosure of tax information	if aggregated to "prevent the identification of particular returns."	if aggregated w/2 other producers	if aggregated w/2 other producers	if aggregated w/2 other producers

Summary Comparison between Various House Approaches to Production Tax

Issue	Current Law	HB 2001 (ACES)	House O&G	House Resources	House Finance
DNR sharing royalty information w/ DOR	limited ability	expanded ability	expanded ability	expanded ability	
DOR sharing tax information with DNR	limited ability	expanded ability	expanded ability	expanded ability	

Statute of Limitations *AS 43.05.260* *Bill Sections 1,14,50 new AS 43.55.075*

State assessment must be issued within	3 yrs	6 yrs	6 yrs	6 yrs
--	-------	-------	-------	-------

DOR Auditors *As 39.25.100* *Bill Sections 10, 65, 67*

DOR & DNR auditors exempt employees?	no	yes	yes	yes
--------------------------------------	----	-----	-----	-----

Effective Date *Bill Section 64*

Generally	n/a	Jan 1 2008	Jan 1 2008	Jan 1 2007
Retroactive to April 1 2006	n/a	deferred maintainance issues	deferred maintainance issues	Loss carryforward, TIE limitations, most cost redefinitions

Downstream Costs *As 43.55.150*

Reasonable v actual	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "or"
<i>Prima facie</i> reasonable Taps Tariff	Filed TAPS tariff	Filed TAPS tariff	Filed TAPS tariff	FMV (TSM not adjudicated just and reasonable)

Gas Ceilings thru 2002 *As 43.55.011*

Where	CI	CI	non North Slope	non North Slope
-------	----	----	-----------------	-----------------

Additional Penalties *new As 43.55.020*

Penalty for under estimated payments	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	5% in addition to IRS Penalties (i.e. interest)
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Summary Comparison between Various House Approaches to Production Tax

Issue	Current Law	HB 2001 (ACES)	House O&G	House Resources	House Finance
DOR & DNR auditors exempt employees?	no	yes	yes	yes	

Effective Date

Bill Section 64

Generally		Jan 1 2008	Jan 1 2008	Jan 1 2007
Retroactive to April 1 2006	n/a	deferred maintaince issues	deferred maintaince issues	Loss carryforward, TIE limitations, most cost redefinitions

Downstream Costs

As 43.55.150

Reasonable v actual	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "or"
<i>Prima facie</i> reasonable Taps Tariff	Filed TAPS tariff	Filed TAPS tariff	Filed T/ PS tariff	FMV (TSM not adjudicated just and reasonable)

Gas Ceilings thru 2002

As 43.55.011

Where	CI	CI	no: North Slope	non North Slope

Additional Penalties

new As 43.55.020

Penalty for under estimated payments	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	5% in addition to IRS Penalties (i.e. interest)

Intent Language

overall intent of legislation	n/a	no	no	included
long standing interpretation of SOL	n/a	included	no	included
Half the money from certain retroactive applications to PERS and public education fund	n/a	no	no	included
tax savings from gas ceilings outside CI passed on to ultimate consumers	n/a	no	no	included

Statutory Reference ACES

CSHB2001(O&G)

CSHB2001(RES)

Title

ACES legislative intent plus the following additions: 1) in state gas uses, 2) ensure fair means of assessing the tax, 3) dedication of retroactivity funds to PERS/TRS and public education fund, savings from Cook Inlet tax changes should enure to the benefit of the ultimate consumer.

Legislative Intent	Refers to limitations of tax assessment Adds requirement for DNR to furnish info to DOR	Legislative intent deleted	
AS 38.05.035(a)	Conforming references	no changes	no changes
AS 38.05.035(b)	Conforming references	no changes	no changes
AS 38.05.036(f)	Conforming references	no changes	no changes
AS 38.05.036(g)	Conforming references	no changes	no changes
AS 38.05.123(f)	Conforming references	no changes	no changes
AS 38.05.133(e)	Conforming references	no changes	no changes
AS 38.05.180(j)	Conforming references	no changes	no changes
AS 38.05.275(c)	Conforming references	no changes	no changes
AS 39.25.110(42)	Adds oil and gas auditors to exempt service	no changes	no changes
AS 41.09.010(d)	Conforming references	no changes	no changes
AS 43.05.230(a)	Provides for an exception to taxpayer confidentiality - AS 43.55.890 expands the data that DOR may provide DNR	no changes	no changes
AS 43.55.230(h)	Conforming references to allow assessment to be filed within six years instead of three years.	no changes	no changes

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AS 43.55.011(e)	reformats sections on how the tax is computed the tax and progressivity are now in (g) and (h) Changes the base tax floor to 10 percent of the total gross value at the point of production for the legacy fields	deletes ACES language thus reverting back to PPT	Amends the current PPT language from a monthly basis to a yearly basis and amends the tax from 22.5 to 25 percent
AS 43.55.011(f)		deletes ACES language thus reverting back to PPT	no changes
AS 43.55.011(g)	establishes the tax rate at 25 percent, the progressivity factor at 0.20 percent and the tax cap at 50%	deletes ACES language - progressivity will be covered in (o)	no changes
AS 43.55.011(h)	sets progressivity on a calendar year basis instead of a monthly basis and establishes the subtraction factor at 30 instead of 40	deletes ACES language - progressivity will be covered in (o)	no changes
AS 43.55.011(j)	technical changes	technical changes deleted	no changes
AS 43.55.011(k)	technical changes	technical changes deleted	no changes
AS 43.55.011(l)	n/a	Conforming reference changes	no changes
AS 43.55.011(m)	minor technical changes and clarifies what a producer could claim in excess credits from Cook Inlet against taxes on leases or properties elsewhere in the state.	added conforming reference changes and deletes the added Cook Inlet language	no changes

AS 43.55.011(o)		establishes a progressivity tax of 0.225 percent based on the gross value at the point of production starting at an ANS wellhead price of \$50	establishes a progressivity tax of 0.2 percent and starting at \$30 net and increasing a 0.3 percent above \$40, 0.4 percent above \$50, 0.5 percent above \$60. The chart accompanying the Amendment implied a 50% cap but the amendment did not state a cap. for gas produced outside the Cook Inlet basin but used in the state, it will have the same tax as gas in Cook Inlet basin.
AS 43.55.011(p)	n/a	n/a	
AS 43.55.020(a)	Makes installment payments consistent with changes to the production tax Conforming changes to ACES language	reverts back to PPT with conforming amendments	no changes
AS 43.55.020(d)	minor language changes	Conforming reference changes	no changes
AS 43.55.020(g)	minor language changes	minor language changes	no changes
AS 43.55.020(h)	minor language changes	minor language changes	no changes
AS 43.55.020(i)	n/a	n/a	new section provides a civil penalty on installment payments of 5% of the difference between the amount due and the amount paid.
AS 43.55.023(a)	stipulates that no more than half a tax credit may be taken in a single year. Amends requirements for submitting data to DNR as a condition of taking the credit.	deletes ACES language	no changes

AS 43.55.023(b)	increases the credit for the amount of the carry forward annual loss from 20% to 25%.	deletes the ACES language	reinstates the intent of the ACES language but refers to the tax rate instead of a specific number, thus maintaining consistency between the tax rate and the rate of the carry forward annual loss.
AS 43.55.023(d)	Conforming amendments for transferrable tax credit certificates and cash payments and extends the timeframe for DOR to approve the application from 60 days to 120 days.	reverts back to PPT with conforming amendments	reestablishes the ability to obtain a cash payment but leaves the timeframe at 60 days.
AS 43.55.023(e)	Conforming references	deletes ACES language	no changes
AS 43.55.023(g)	Conforming language related to the purchase of a certificate	deletes ACES language TIE credits are reinstated but the qualifying period is changes from March 2001 to March 2003	reinstates ACES language related to the purchase of a certificate
AS 43.55.023(i)	TIE credits are not in ACES because they are repealed in Section 65 clarifies that tax exempt entities are not eligible for transferrable tax certificates	no changes	no changes
AS 43.55.023(l)			
AS 43.55.023(m)	n/a	n/a	provides that to the extent that the Alaska Retirement Management Board is authorized to purchase the certificates, the department may issue a cash refund to the Board
AS 43.55.024(a)	provides that 0.24 credits cannot be applied against the tax floor in .011(f)	deletes ACES language	no changes
AS 43.55.024(c)	provides that 0.24 credits cannot be applied against the tax floor in .011(f)	deletes ACES language	no changes

AS 43.55.024(e)	provides that 0.24 credits cannot be applied against the tax floor in .011(f) deletes ACES language	no changes
AS 43.55.024(g)	provides that 0.24 credits cannot be applied against the tax floor in .011(f) deletes ACES language	no changes Reinstates ACES language and changes the 20 percent credit to 30 percent ..
AS 43.55.025(a)	provides that 0.25 credits cannot be applied against the tax floor in .011(f) deletes ACES language	reinstates ACES language but changes the qualification date for work performed from 12/1/07 to 12/0/06 and adds "suspended" to "completed and abandoned"
AS 43.55.025(b)	requires that the well must be "completed or abandoned" prior to receiving the credit. Exempts costs arising from gross negligence and violations of HS&E statutes and regs. deletes ACES language	Reinstates ACES language with 20% to 30% changes
AS 43.55.025(c)	adds additional requirements of DNR approval in advance and verification subsequent to drilling the well deletes ACES language	reinstated the ACES language with the following changes: provided the DNR commissioner the discretion to grant extended confidentiality under certain circumstances; made the certificates immediately available.
AS 43.55.025(f)	defines the data that would be necessary to be submitted to receive an exploration credit. Reduces the confidentiality period from 10 years to 2 years. Provides that two certificates would be issued, one-half the credit immediately useable and one-half delayed a year. deletes ACES language	reinstates ACES language
AS 43.55.025(g)	clarifies that tax exempt entities are not eligible for transferrable tax certificates deletes ACES language	reinstates ACES language
AS 43.55.025(h)	provides that .025 credits cannot be applied against the tax floor in .011(f) deletes ACES language	reinstates ACES language

AS 43.55.025(i)	deletes producer's ability to apply tax credit against the tax floor in .011(f)	deletes ACES language	reinstates ACES language
	changes the definition of preexisting well from a well spudded within 120 days to a well spudded within 540 days		
AS 43.55.025(k)	allows DNR to purchase seismic with credits for 5% of investment	deletes ACES language	reinstates ACES language
AS 43.55.025(l)	expenditure	deletes ACES language	reinstates ACES language
			to the extent that the Alaska Retirement Management Board is authorized to purchase transferrable tax credits, the department is authorized to issue a cash refund the the ARMB.
AS 43.55.025(m)	n/a	n/a	reinstates the ACES language with the following changes: sets a maximum annual limit of \$25 million on the purchase of certificates except the maximum does not apply to the ARMB.
	creates the oil and gas tax credit fund and establishes the amount of reserve to be deposited into the fund.		
AS 43.55.028		deletes ACES language	
	amends what a taxpayer is require to file to include costs of transportation of oil and gas, qualified capital expenditures, and lease expenditures, and the production tax value of the oil and gas	no changes	no changes
AS 43.55.030(a)	establishes a \$1000 a day penalty for not filing required reports		
AS 43.55.030(d)		deletes the ACES language	reinstates the ACES language

AS 43.55.030(e)	requires reporting obligations to explorers that do not have production	no changes	no changes
AS 43.55.040	grants the power to the DOR to require producers and explorers to file reports that are "considered necessary" to forecast state revenue under AS 43.55. Also provides for penalties of \$1000 per day for not filing required reports	deletes the penalties portion of the ACES language	reinstates the ACES language and provides for interest on the penalty and prohibits the department from compromising on the penalty for less than 50% of the penalty assessed.
AS 43.55.075	extends the time the department is required to file an assessment from 3 years to 6 years.	no changes	no changes
AS 43.55.110(e)	allows the department to require electronic filing	no changes	no changes
AS 43.55.150(a)	n/a	n/a	for purposes of determining the reasonable transportation costs of oil and gas, actual costs are considered reasonable transportation costs unless 1) the parties to the transportation of oil and gas are affiliated, 2) the contract is not at arms length or representative of the market "OR" methods of transport are not reasonable. The current law requires all three contingencies, the proposed law requires any one of the contingencies.

			If the one of the contingencies in (a) occurs, the department will determine what is reasonable. Transportation costs that are merely filed with the RCA are not prima facie reasonable anymore, they must now be adjudicated.
AS 43.55.150(b)	n/a	n/a	added the exclusion of gas under .011(p) from gas not produced in Cook Inlet.
AS 43.55.160(a)	clarifies how production tax values are calculated in Cook Inlet	changed back to PPT language with conforming references	
AS 43.55.160(b)	continues the clarification from (a) extends loss carry forwards to costs associated with leases of a producer that are not producing oil and gas or are on lands where the producer does not own an operating or working interest.	deletes the ACES language	no changes
AS 43.55.160(e)		deletes ACES language	no changes
	this section deals with allocations of costs that a taxpayer incurs in one lease or property against revenues from another lease or property. Proposed North Slope rules are in (f); new area development rules are in (g); and Cook Inlet rules are in (h) and (i).		
AS 43.55.160(f-i)	describes the types of costs that qualify as lease expenditures and provides standards for the department to determine which costs are allowed.	deletes ACES language	no changes
AS 43.55.165(a)		deletes ACES language and reverts to PPT language with conforming references	no changes

reinstates ACES language but adds the allowance for reasonable overhead expenses and requires that the activity must be physically located in the state in order for the cost of the activity to be a cost upstream of the point of production.

amends the previous language of physically located "in the state" to physically located "on the premises of the lease or property from which oil or gas is recovered"

adds criminal negligence and violations of the Clean Water Act to things disallowed under (6); adds lobbying, public relations and advertising to costs disallowed under (8); deleted (19) effectively reinstating those costs as eligible costs; adding a new section (20) disallowing costs relating to office buildings, fixtures, and equipment, and real property that are not located in the state.

amends the department's responsibility to write regs to cover the allocation of costs under .011(p) and other gas.

AS 43.55.165(b) deletes language for the allowance of reasonable overhead expenses. deletes ACES language

AS 43.55.165(b) n/a n/a

AS 43.55.165(e) section (6) disallows costs arising from violations of law, or failure to comply with a lease obligation, changes to (15) disallows the remaining dismantlement, removal and abandonment costs that were allowed by PPT, (19) disallows costs for repair, replacement, or deferred maintenance from an unscheduled interruption or reduction in rate of oil or gas, (20) disallows costs associated with a refinery or crude oil topping plant. expands the responsibility of the department to write regulations covering any required allocation of costs. no changes

AS 43.55.165(h) deletes the ACES language

AS 43.55.170(a)	deletes qualifying language regarding payment or credit that has already been subtracted in calculating billable or billed costs under .165(c) and (d)	no changes	no changes
AS 43.55.890	this section allows the department to disclose tax information of the information is aggregated from three or more taxpayers.	no changes	no changes
AS 43.55.900	Definitions: "nonunitized reservoir", "pool", "producer", and "unit"	deletes "nonunitized reservoir" and "pool"	adds definition of "used in the state"
Effective date of Taxes	1-Jan-08	1-Jan-08	1-Jan-07

HB 20001 (RES)

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

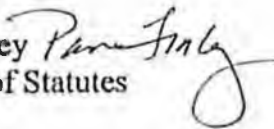
State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

November 6, 2007

SUBJECT: CSHB 2001(RES): Version V
(Work Order No. 25-GH0014V)

TO: Representative Carl Gatto
Co-chair of the House Resources Committee
Attn: Bonnie

FROM: Pam Finley 
Revisor of Statutes

Enclosed is a final of the referenced CS. The differences between this version and the O version are as follows:

1. In sec. 50, in AS 43.55.160(a)(2)(E), "1/2" was changed to "1/12".
2. In AS 43.55.028(c)(7), the words "or by" were added.
3. AS 43.55.850 was deleted and a general statement of its contents was added as intent language in sec. 1(c). Cross-references to AS 43.55.850 in the back pages were deleted.
4. In sec. 1(b), "the public education fund" was substituted for a general reference to education funding.
5. To correct errors in the back pages, the following changes were made. AS 43.55.023(d) was added to sec. 61(a). Section 26 was deleted from sec. 61(b). Section 52 was added to sec. 66(b). In sec. 66(b), AS 43.55.023 was substituted for AS 43.55.030. Section 44 was deleted from sec. 66(c).

Please let us know if any of the changes above were inappropriate.

PF:med
07-410.med

Enclosure

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 4
Bill Version: CSHB 2001(RES)
(H) Publish Date: 11/6/07

Identifier (file name): CSHB2001(RES) DOR-TAX-11-5-07 Dept. Affected: Revenue 04
Title: An Act relating to the production tax on oil and gas.. RDU: Taxation and Treasury
Sponsor: Governor Component: Tax Division
Requester: House Finance Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information						
		FY 2009	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
OPERATING EXPENDITURES								
Personal Services	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7
Travel								
Contractual	1,018.4	1,018.4	1,018.4	511.8	5.2	5.2	5.2	5.2
Supplies								
Equipment								
Land & Structures								
Grants & Claims								
Miscellaneous								
TOTAL OPERATING	2,234.1	2,234.1	2,234.1	1,727.5	1,220.9	1,220.9	1,220.9	1,220.9

CAPITAL EXPENDITURES								
-----------------------------	--	--	--	--	--	--	--	--

CHANGE IN REVENUES ()		727,000.0	513,000.0	566,000.0	835,000.0	813,000.0	596,000.0
-------------------------------	--	------------------	------------------	------------------	------------------	------------------	------------------

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	2,234.1	2,234.1	2,234.1	1,727.5	1,220.9	1,220.9	645.9
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	2,234.1	2,234.1	2,234.1	1,727.5	1,220.9	1,220.9	645.9

Estimate of any current year (FY2008) cost: 3,409.2

POSITIONS

Full-time	1	1	1	1	1	1	1
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

This bill makes economic and several administrative changes to the state's current petroleum profits tax. The bill retains the current tax system's structure, which taxes the net value of petroleum resources. The bill makes the following changes to the current system: It institutes a rate of 25% on net income. It calculates the progressivity surcharge as the difference between the per barrel net revenue and \$30 at 0.2%, 0.3% between \$40 and \$50, 0.4% between \$50 and \$60, and 0.5% over \$60. It eliminates the period by which past investments are recognized in the transition investment expenditure credits (AS 43.55.023(i)) from April 1, 2001 to April 1, 2003. Pipeline tariffs are based on reasonable rates. EIC credits are increased from 20% to 30%. The effective date of the bill is January 1, 2007.

Prepared by: Johanna Bales, Roger Marks, Cherie Nienhuis
Division: Tax Division
Approved by: Jerry Burnett
Department of Revenue

Phone 269-6628
Date/Time 11/5/07 11:00 AM
Date 11/5/2007

ANALYSIS CONTINUATION

Administrative changes to the current tax system include the following: those expenses related to criminal negligence; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas auditors.

Certain lease expenditure allowance provisions are retroactive to April 1, 2006; the other provisions of the tax proposal become effective January 1, 2007.

Personal Services: The department will reclassify the existing 5 vacant auditor positions, and create 4 to 5 senior level auditor positions with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables and will be beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. In addition, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of \$115,700 annually. The existing oil and gas specialist, oil and gas revenue auditors, and their immediate supervisor will be offered the opportunity to opt into an exempt status with individual salaries established commensurate with experience and skill level, and consistent with market comparables.

The need for exempt status is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The current pay range for an Oil and Gas Revenue Auditor is on the low range of the pay range for roughly similar jobs. The department estimates the new exempt positions and the potential salary increases associated with the change of existing staff to exempt status, will cost the state approximately \$1,100,000 annually.

Contractual: Contractual expenditures include \$1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of \$100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax. The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional \$5,200 each year in contractual costs associated with the new Analyst Programmer V position.

Current FY2008 costs: The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - \$2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and \$506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - \$218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately \$57,800. **Supplies** - \$6,000 for a computer and software for the new analyst programmer V position.

See page 3 for projected revenue estimates.

STATE OF ALASKA
2008 LEGISLATIVE SESSION

ANALYSIS CONTINUATION

Estimated Production Tax Revenues, PPT and ACES, at
Various Prices (in \$millions nominal)

Fall 2007 DOR Official Forecast Prices

Fiscal Year	ANS WC \$ per barrel (in REAL dollars)	ANS WC \$ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSHB2001 (Res)	Increase or (Decrease) from PPT
2008	71.65	71.65	1,915	2,970	1,055
2009	64.55	66.30	1,693	2,420	727
2010	60.05	63.40	1,531	2,044	513
2011	59.70	64.75	1,670	2,236	566
2012	59.55	66.35	1,746	2,581	835
2013	58.90	67.45	1,647	2,460	813
2014	58.25	68.55	1,642	2,238	596

DOR Forecast nominal prices rounded to the nearest \$0.05

\$60 per barrel in REAL dollars

Fiscal Year	ANS WC \$ per barrel (in REAL dollars)	ANS WC \$ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSHB2001 (Res)	Increase or (Decrease) from PPT
2008	60.00	60.00	1,051	1,688	637
2009	60.00	61.65	1,435	2,038	603
2010	60.00	63.35	1,562	2,081	519
2011	60.00	65.09	1,695	2,271	576
2012	60.00	66.88	1,783	2,632	849
2013	60.00	68.72	1,733	2,587	854
2014	60.00	70.61	1,776	2,437	661

\$80 per barrel in REAL dollars

Fiscal Year	ANS WC \$ per barrel (in REAL dollars)	ANS WC \$ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSHB2001 (Res)	Increase or (Decrease) from PPT
2008	80.00	80.00	2,650	4,146	1,496
2009	80.00	82.20	3,031	4,489	1,458
2010	80.00	84.46	3,266	4,700	1,434
2011	80.00	86.78	3,481	5,071	1,590
2012	80.00	89.17	3,668	5,667	1,999
2013	80.00	91.62	3,619	5,669	2,050
2014	80.00	94.14	3,690	5,585	1,895

Additional revenues for the second half of FY 2007 would be \$244 million.

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 5
Bill Version: CSHB 2001(RES)
(H) Publish Date: 11/6/07

Identifier (file name): HB2001CSRES-DNR-O&G-11-06-07 Dept. Directed: Natural Resources
Title: Oil and Gas Tax Amendments RDU: Resource Development
Component: Oil and Gas Development
Sponsor: Rules Committee
Requester: House Finance Component Number: 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation	Information						
	Required	FY 2009	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
OPERATING EXPENDITURES								
Personal Services	303.5		303.5	303.5	303.5	303.5	303.5	303.5
Travel								
Contractual								
Supplies								
Equipment								
Land & Structures								
Grants & Claims								
Miscellaneous								
TOTAL OPERATING	303.5		303.5	303.5	303.5	303.5	303.5	303.5

CAPITAL EXPENDITURES

CHANGE IN REVENUES () **Indeterminate Positive

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	303.5		303.5	303.5	303.5	303.5	303.5
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	303.5	0.0	303.5	303.5	303.5	303.5	303.5

Estimate of any current year (FY2008) cost: 177.0

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

This bill would amend the oil and gas production tax under AS 43.55 to increase the base tax rate from 22.5% to 25% of net income. The bill has the progressivity surcharge increasing at 0.2% per dollar between the per barrel net revenue and \$30, 0.3% between \$30 and \$40; 0.4% between \$50 to \$60, and 0.5% as it goes over \$60. The bill also eliminates the period by which past investments are recognized in the transition investment expenditure credits (AS 43.55.023(i)) from April 1, 2001 to April 1, 2003. In calculating transportation deductions, pipeline tariffs are based on actual and reasonable rates. Some EICs credits are increased from 20% to 30%.

Administrative changes to the current tax system include changes in the administration of EICs under AS 43.55.025 relating to the kind of information that EIC applicants must provide to the state and the time that this information may be kept confidential.

Prepared by: Kevin Banks, Acting Director
Division: Oil and Gas
Approved by: Tom Irwin, Commissioner
Natural Resources

Phone: 269-8800
Date/Time: 11/6/2007
Date: 11/6/2007

FISCAL NOTE #5

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSHB 2001(RES)

ANALYSIS CONTINUATION

*Indeterminate Positive: The royalty revenue impact to the State of ACES is indeterminate, but most likely positive. ACES improves the economics for new entrants or small Alaska producers, but decreases the attractiveness of investments in legacy fields.

As an offset and incentive, the bill would have a fund created that would buy back the credits from small producers (less than 50,000 barrels a day) but payouts are capped at \$25,000,000. Because of this cap, the value of the production tax transferable credits (the Qualified Capital Expenditure credits (AS 43.55.023(a)), the loss carry-forward credit (AS 43.55.023(c)), and EICs (AS 43.55.025) will remain the same as under existing law.

Taken together and comparing the House Resources committee bill with the existing AS 43.55 means that a North Slope oil development project's value (the net present value at a 15% discount rate) to the new entrant will be less. At \$40 per barrel (ANS West Coast), the NPV goes down about 10% for these new entrant's projects. Existing producers will see a bigger decrease in the NPV of their new capital investments at \$40 per barrel because the TIE credit is eliminated. At higher prices (between \$50 and \$85), the higher tax rate will lower project net present values by as much as 35% but the remaining project NPVs at these higher prices will be high enough to still attract investment. These new investments will lead to more production and royalty revenue.

This bill also excludes certain types of costs from being deductible lease expenditures when determining net income. Expenses relating to criminal negligence and dismantlement, removal & restoration (DR&R) costs would no longer be deductible lease expenditure. The impact of these exclusions are unknown and not estimated here.

Personal Services: This bill would reclassify the current oil and gas auditors to exempt status employees. DO&G currently has seven oil and gas auditor positions. The total salary/benefit costs for these seven employees currently equals approximately \$849,147. An increase to exempt status is estimated to cost up to an additional \$303,500 in FY09. The FY08 amount of \$177,000 covers an estimated 7 months at the higher rate.

11/4/07

CSHB 2001(O&G) Version L

Amendment	Sponsor	Section	Action	Notes
First Batch				
1	Seaton	18	withdrawn	
2	Seaton	23	adopted 7-2	L.42
3	Seaton	23	adopted no objection	L.14
4	Wilson	23	adopted no objection	L.15
5	Roses/Wilson	25	adopted no objection	L.4
6	Wilson	26	adopted as amended	L.76
7	Roses	27	adopted	L.25
8	Fairclough	28	adopted	L.26
9	Seaton	32	withdrawn	
10	Seaton/Johnson	32	adopted	L.13
11	Johnson/Roses/Wilson	33	adopted	L.12
12	Fairclough	18	failed 4-5	
13	Fairclough	29	failed	
Second Batch				
14	Johnson	12	withdrawn	
15	Johnson	13	failed 1-8	
16	Guttenberg	10	failed 3-6	
17	Guttenberg	1	withdrawn	
18	Edgmon	11	withdrawn	
19	Guttenberg	13	failed	
20	Edgmon	23	withdrawn	
21	Edgmon	25	withdrawn	
22	Kawasaki	29	failed	
23	Edgmon	32	withdrawn	
24	Guttenberg	34	adopted /amended , not Leg. Svcs.	
25	Guttenberg	32	withdrawn	
26	Seaton	18	withdrawn	
Third Batch				
27	Guttenberg	9	withdrawn	
28	Guttenberg	23	withdrawn	
29	Guttenberg	23	adopted w/concept. amend.	L.51
30	Guttenberg	24	withdrawn	
31	Guttenberg	24	failed 4-5	
32	Edgmon	26	adopted then reversed/failed	
33	Guttenberg	32	withdrawn	
34	Guttenberg	36	withdrawn	
35	Guttenberg	42	withdrawn	
Fourth Batch				
36	Kawasaki	1	adopted/amended	L.77
37	Kawasaki	1	withdrawn	
38	Guttenberg	1	adopted as amended	L.71
39	Guttenberg	14	withdrawn	

40	Guttenberg	23	withdrawn	
41	Guttenberg	23	withdrawn	
42	Guttenberg	26	withdrawn	
43	Edgmon	33	adopted/amended	L.68
44	Gatto	14	adopted/amended	L.72
45	Seaton	33	withdrawn	
46	Guttenberg	30	withdrawn	

~~PROGRESSIVITY - follow O&G~~
brought goes to ACES trigger point @ 30
mp @ 10:30 pm

AMENDMENT

(2) ~~adopted~~
7-2

OFFERED IN THE HOUSE

TO: CSHB 2001(O&G)

BY REPRESENTATIVE SEATON

Y N
K J
G U F
E E W
R

NET PROFIT	
30 ⁰⁰	.20
40 ⁰⁰	.30
50	.40
60	.50

1 Page 13, lines 8 - 22:

2 Delete all material and insert:

3 "(o) In addition to the tax levied under (e) of this section, for each month for
 4 which the producer's average monthly production tax value of the taxable oil and gas
 5 exceeds \$30 for each BTU equivalent barrel, there is levied on the producer of oil or
 6 gas a tax for all oil and gas produced that month from each lease or property in the
 7 state, less any oil and gas the ownership or right to which is exempt from taxation or
 8 constitutes a landowner's royalty interest. Except as otherwise provided under (j) and
 9 (k) of this section, the tax levied under this subsection is equal to the sum over all
 10 months of the calendar year of the amount calculated under this subsection. For each
 11 month for which this subsection applies and for which the average monthly production
 12 tax value of the taxable oil and gas is

13 (1) not more than \$40 for each BTU equivalent barrel, the tax is equal
 14 to 0.2 percent of the gross value at the point of production of the taxable oil and gas
 15 for that month multiplied by the number that represents the difference between the
 16 average production tax value for each BTU equivalent barrel of the taxable oil and gas
 17 for that month and \$30; or

18 (2) more than \$40 but not more than \$50 for each BTU equivalent
 19 barrel, the tax is equal to two percent of the gross value at the point of production of
 20 the taxable oil and gas for that month plus 0.3 percent of the gross value at the point of
 21 production of the taxable oil and gas for that month multiplied by the number that
 22 represents the difference between the average production tax value for each BTU
 23 equivalent barrel of the taxable oil and gas for that month and \$40;

1 (3) more than \$50 but not more than \$60 for each BTU equivalent
2 barrel, the tax is equal to five percent of the gross value at the point of production of
3 the taxable oil and gas for that month plus 0.4 percent of the gross value at the point of
4 production of the taxable oil and gas for that month multiplied by the number that
5 represents the difference between the average production tax value for each BTU
6 equivalent barrel of the taxable oil and gas for that month and \$50;

7 (4) more than \$60 for each BTU equivalent barrel, the tax is equal to
8 nine percent of the gross value at the point of production of the taxable oil and gas for
9 that month plus 0.5 percent of the gross value at the point of production of the taxable
10 oil and gas for that month multiplied by the number that represents the difference
11 between the average production tax value for each BTU equivalent barrel of the
12 taxable oil and gas for that month and \$60."

AMENDMENT

3

OFFERED IN THE HOUSE
TO: CSHB 2001(O&G)

BY REPRESENTATIVE SEATON

adopted

1 Page 17, following line 3:

2 Insert a new bill section to read:

3 **** Sec. 23. AS 43.55.023(b) is amended to read:**

4 (b) A producer or explorer may elect to take a tax credit in the amount of the
5 [20 PERCENT OF A] carried-forward annual loss multiplied by the nominal tax
6 rate in AS 43.55.011(e). A credit under this subsection may be applied against a tax
7 due under AS 43.55.011(e). For purposes of this subsection,

8 (1) a carried-forward annual loss is the amount of a producer's or
9 explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a
10 previous calendar year that was not deductible for that calendar year under
11 AS 43.55.160(b) and (c); and

12 (2) "nominal tax rate" means the tax rate stated in AS 43.55.011(e)
13 that is not the tax determined at the minimum tax rate that may be applicable
14 under AS 43.55.011(f).

15

16 Renumber the following bill sections accordingly.

17

18 Page 31, line 25:

19 Delete "Sections 24, 25, 32 - 34, and 37"

20 Insert "Sections 23, 25, 26, 33 - 35, and 38"

21

22 Page 31, line 27:

23 Delete "31, and 38"

- 1 Insert "32, and 39"
- 2
- 3 Page 31, line 29:
- 4 Delete "Sections 26 and 27"
- 5 Insert "Sections 27 and 28"
- 6
- 7 Page 31, line 30:
- 8 Delete "sec. 26"
- 9 Insert "sec. 27"
- 10
- 11 Page 31, line 31:
- 12 Delete "sec. 27"
- 13 Insert "sec. 28"
- 14
- 15 Page 32, line 1:
- 16 Delete "sec. 29"
- 17 Insert "sec. 30"
- 18
- 19 Page 32, line 3:
- 20 Delete "29"
- 21 Insert "30"
- 22
- 23 Page 32, line 31:
- 24 Delete "secs. 24, 25, 32 - 34, and 37"
- 25 Insert "secs. 23, 25, 26, 33 - 35, and 38"
- 26
- 27 Page 33, line 2:
- 28 Delete "26, 27, 31, and 38"
- 29 Insert "27, 28, 32, and 39"
- 30
- 31 Page 33, lines 19 - 20:

1 Delete "Sections 24, 25, 32 - 34, and 37"

2 Insert "Sections 23, 25, 26, 33 - 35, and 38"

3

4 Page 33, line 21:

5 Delete "26, 27, 31, and 38"

6 Insert "27, 28, 32, and 39"

7

8 Page 33, line 22:

9 Delete "sec. 44"

10 Insert "sec. 45"

AMENDMENT

4

adopted

OFFERED IN THE HOUSE
TO: CSHB 2001(O&G)

BY REPRESENTATIVE SEATON
+ Rep. Wilson

1 Page 1, line 4, following "latitude;":

2 Insert "providing a penalty for the underpayment of an installment payment of
3 the production tax on oil and gas;"

4
5 Page 17, following line 3:

6 Insert a new bill section to read:

7 "* Sec. 23. AS 43.55.020 is amended by adding a new subsection to read:

8 (i) A civil penalty shall be added to the amount of an installment payment
9 required under (a)(1) - (4) of this section if the full amount of the payment is not paid
10 by the date the payment is due. The penalty is equal to five percent of the difference
11 between the amount of the installment payment that was made timely and the amount
12 of the installment payment required under (a)(1) - (4) of this section. If no part of the
13 required installment payment was made timely, the penalty is equal to five percent of
14 the installment payment required under (a)(1) - (4) of this section. The penalty is in
15 addition to the interest imposed under (g) of this section and a penalty added under
16 AS 43.05.220, if any."

17
18 Renumber the following bill sections accordingly.

19
20 Page 31, line 25:

21 Delete "Sections 24, 25, 32 - 34, and 37"

22 Insert "Sections 25, 26, 33 - 35, and 38"

23

1 Page 31, line 27:

2 Delete "31, and 38"

3 Insert "32, and 39"

4

5 Page 31, line 29:

6 Delete "Sections 26 and 27"

7 Insert "Sections 27 and 28"

8

9 Page 31, line 30:

10 Delete "sec. 26"

11 Insert "sec. 27"

12

13 Page 31, line 31:

14 Delete "sec. 27"

15 Insert "sec. 28"

16

17 Page 32, line 1:

18 Delete "sec. 29"

19 Insert "sec. 30"

20

21 Page 32, line 3:

22 Delete "29"

23 Insert "30"

24

25 Page 32, line 31:

26 Delete "secs. 24, 25, 32 - 34, and 37"

27 Insert "secs. 25, 26, 33 - 35, and 38"

28

29 Page 33, line 2:

30 Delete "26, 27, 31, and 38"

31 Insert "27, 28, 32, and 39"

1

2 Page 33, lines 19 - 20:

3 Delete "Sections 24, 25, 32 - 34, and 37"

4 Insert "Sections 25, 26, 33 - 35, and 38"

5

6 Page 33, line 21:

7 Delete "26, 27, 31, and 38"

8 Insert "27, 28, 32, and 39"

9

10 Page 33, line 22:

11 Delete "sec. 44"

12 Insert "sec. 45"

AMENDMENT 5

adopted

OFFERED IN THE HOUSE
TO: CSHB 2001(O&G)

BY REPRESENTATIVE SEATON
Rep. Roses
Rep. Wilson

1 Page 18, line 23:

2 Delete "a new subsection"

3 Insert "new subsections"

4

5 Page 18, following line 25:

6 Insert new material to read:

7 "(m) Notwithstanding the limitation on the use of a transferable tax credit by a
8 transferee under (c) of this section and subject to appropriations made by law, if and to
9 the extent that purchase of transferable tax credits by the Alaska Retirement
10 Management Board is authorized by law, the department shall issue a cash refund to
11 the Alaska Retirement Management Board for a transferable tax credit originally
12 issued to a person under (d) of this section and purchased by the Alaska Retirement
13 Management Board.

14 * Sec. 26. AS 43.55.025 is amended by adding a new subsection to read:

15 (l) Subject to appropriations made by law, if and to the extent that purchase of
16 transferable tax credits by the Alaska Retirement Management Board is authorized by
17 law, the department shall issue a cash refund to the Alaska Retirement Management
18 Board for a transferable tax credit originally issued to an explorer under (i) this
19 section and purchased by the Alaska Retirement Management Board."

20

21 Renumber the following bill sections accordingly.

22

23 Page 31, line 25:

- 1 Delete "Sections 24, 25, 32 - 34, and 37"
- 2 Insert "Sections 24 - 26, 33 - 35, and 38"
- 3
- 4 Page 31, line 27:
 - 5 Delete "31, and 38"
 - 6 Insert "32, and 39"
 - 7
- 8 Page 31, line 29:
 - 9 Delete "Sections 26 and 27"
 - 10 Insert "Sections 27 and 28"
 - 11
- 12 Page 31, line 30:
 - 13 Delete "sec. 26"
 - 14 Insert "sec. 27"
 - 15
- 16 Page 31, line 31:
 - 17 Delete "sec. 27"
 - 18 Insert "sec. 28"
 - 19
- 20 Page 32, line 1:
 - 21 Delete "sec. 29"
 - 22 Insert "sec. 30"
 - 23
- 24 Page 32, line 3:
 - 25 Delete "29"
 - 26 Insert "30"
 - 27
- 28 Page 32, line 31:
 - 29 Delete "secs. 24, 25, 32 - 34, and 37"
 - 30 Insert "secs. 24 - 26, 33 - 35, and 38"
 - 31

1 Page 33, line 2:

2 Delete "secs. 14 - 20, 26, 27, 31, and 38"

3 Insert "secs. 14 - 20, 27, 28, 32, and 39"

4

5 Page 33, lines 19 - 20:

6 Delete "Sections 24, 25, 32 - 34, and 37"

7 Insert "Sections 24 - 26, 33 - 35, and 38"

8

9 Page 33, line 21:

10 Delete "26, 27, 31, and 38"

11 Insert "27, 28, 32, and 39"

12

13 Page 33, line 22:

14 Delete "sec. 44"

15 Insert "sec. 45"

(Wilson)
amendment # 1, pg 2, line 22
insert "before or"
Adopted
6

25-GH0014L.76
Bullard/Bulleck
11/4/07

AMENDMENT

OFFERED IN THE HOUSE
TO: CSHB 2001(O&G)

BY REPRESENTATIVE WILSON

1 Page 18, following line 25:

2 Insert new bill sections to read:

3 "* Sec. 26. AS 43.55.025(a) is amended to read:

4 (a) Subject to the terms and conditions of this section, a credit against the
5 production tax levied by [DUE UNDER] AS 43.55.011(e) [OR (f)] is allowed for
6 exploration expenditures that qualify under (b) of this section in an amount equal to
7 one of the following:

8 (1) 30 [20] percent of the total exploration expenditures that qualify
9 only under (b) and (c) of this section;

10 (2) 30 [20] PERCENT of the total exploration expenditures [FOR
11 WORK PERFORMED BEFORE JULY 1, 2007, AND] that qualify only under (b)
12 and (d) of this section;

13 (3) 40 percent of the total exploration expenditures that qualify under
14 (b), (c), and (d) of this section; or

15 (4) 40 percent of the total exploration expenditures that qualify only
16 under (b) and (c) of this section.

17 * Sec. 27. AS 43.55.025(b) is amended to read:

18 (b) To qualify for the production tax credit under (a) of this section, an
19 exploration expenditure must be incurred for work performed [ON OR] after
20 December 31, 2007 [JULY 1, 2003], and before July 1, 2016, [EXCEPT THAT AN
21 EXPLORATION EXPENDITURE FOR A COOK INLET PROSPECT MUST BE
22 INCURRED FOR WORK PERFORMED ON OR AFTER JULY 1, 2005,] and

23 (1) may be for seismic or other geophysical exploration costs not

1 connected with a specific well;

2 (2) if for an exploration well,

3 (A) must be incurred by an explorer that holds an interest in the
4 exploration well for which the production tax credit is claimed;

5 (B) may be for either a [AN OIL OR GAS DISCOVERY] well
6 that encounters an oil or gas deposit or a dry hole; [AND]

7 (C) must be for a well that has been completed, suspended,
8 or abandoned under AS 31.05.030 at the time the explorer claims the tax
9 credit under (f) of this section; and

10 (D) must be for goods, services, or rentals of personal property
11 reasonably required for the surface preparation, drilling, casing, cementing,
12 and logging of an exploration well, and, in the case of a dry hole, for the
13 expenses required for abandonment if the well is abandoned within 18 months
14 after the date the well was spudded;

15 (3) may not be for [TESTING, STIMULATION, OR COMPLETION
16 COSTS;] administration, supervision, engineering, or lease operating costs; geological
17 or management costs; community relations or environmental costs; bonuses, taxes, or
18 other payments to governments related to the well; costs arising from gross
19 negligence or violation of health, safety, or environmental statutes or regulations;
20 or other costs that are generally recognized as indirect costs or financing costs; and

21 (4) may not be incurred for an exploration well or seismic exploration
22 that is included in a plan of exploration or a plan of development for any unit on
23 May 13, 2003.

24 * Sec. 28. AS 43.55.025(c) is repealed and reenacted to read:

25 (c) To be eligible for the 30 percent production tax credit authorized by (a)(1)
26 of this section or the 40 percent production tax credit authorized by (a)(3) of this
27 section, exploration expenditures must

28 (1) qualify under (b) of this section; and

29 (2) be for an exploration well, subject to the following:

30 (A) before spudding the well, (i) the explorer shall submit to
31 the commissioner of natural resources the information necessary to determine