THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

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February 7, 2013

The Honorable Berta Gardner
Alaska State Senator
State Capitol, Room 417
Juneau, AK 99801-1182

Dear Senator Gardner:

I am writing in response to your February 1, 2013 letter with questions that arose during the Econ One Research presentation. I have worked with Mr. Pulliam and our economic research staff to answer your questions below. Please see questions in italics and our responses immediately below the questions.

1. *In recent years in Alaska there has been discussion about the majors being in "harvest mode." Is there any reason to believe that this characterization is incorrect?*

   Alaska's majors (defined here as CP, EM and BP) continue to develop their properties, which have billions of additional recoverable barrels in reserves. In addition, they are expanding (in the case of Conoco at CD-5 and Exxon and BP at Pt. Thompson) and have attempted to develop new fields (e.g., Liberty for BP) but have met with technical challenges. In addition, they have invested in recent years in updating older facilities in aging fields, facilities that will enable these fields to produce for many years to come. These activities are not consistent with companies that are in "harvest mode."

2. *Slide 26: Producer spending (in red) between 2007 and 2012 is roughly level while "all other" spending (in green) is doubled over the same period. We don't really know if producers were doing new work or maintenance work, but does the green portion indicate that ACES was successful in bringing new participants to Alaska?*

   Capital spending by large producers (red) grew by approximately $250 million between 2007 and 2012. At the same time, capital spending by all others (green) grew by approximately $320 million. The growth in "all others" over this period overlaps with the development of Oooguruk and Nikaitchuq by Pioneer Natural Resources and ENI, though the (green) spending in Chart 26 encompasses additional companies.

   Pioneer Natural Resources is the operator at Oooguruk and has a 70% working interest, which it acquired in 2002 during the ELF period. ENI holds the remaining 30%, which it acquired through the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005, also during the ELF period. The project was sanctioned in January 2006.

   ENI is the operator of Nikaitchuq. ENI acquired a 30% interest in Nikaitchuq with the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005. ENI acquired the remaining 70% interest in the Unit from Anadarko in March 2007. Anadarko in turn acquired its interest from Kerr-McGee.

KMG/Armstrong, ENI's predecessor in interest at Nikaitchuq, began drilling exploration and appraisal wells in the 2003-2004 season and drilled six wells prior to 2006. ENI sanctioned development of Nikaitchuq in February 2008 after receiving royalty relief approval from DNR in the second half of 2007.

ENI also owned interests in the North Tarn field (Mustang), which it acquired from Armstrong in August 2005. ENI farmed out its interests in these properties in 2010 to Brooks Range and a group of independents. Brooks Range and its partners are actively trying to advance Mustang and other projects as well.

With these background facts in mind, I do not believe that the rise in spending by "all others" shown in Slide 26 indicates that ACES (or its provisions) brought new participants to Alaska.

3. *Slide 27: Does this slide show that spending for new units increased 2 ½ times under ACES?*

Slide 27 shows that spending for units not in production as of 2003 (Oooguruk, Nikaitchuq, Pt. Thomson and others) increased from $426 million in 2007 to $1,091 million in 2012. 2012 spending was approximately 2.5 times the level of 2007 spending. This represents an increase of approximately 150% during the period in which ACES has been in effect.

4. *Slide 38: This is an area profile for Australia. Can you explain why both employment and capital spending increased dramatically during the period 2002-2011 but Drilling/Development dropped beginning in 2006?*

This slide shows employment and capital spending growing through 2011, while drilling is declining from 2006 forward. I believe these inverse trends are likely the result of two factors. First, the employment data from Australia includes mining operations, not just petroleum operations. We do not have a separate breakout for petroleum employment in Australia. Second, much of the capital spending in Australia has been related to LNG development which will include significant spending on facilities rather than drilling.

5. *Slide 43: Employment is climbing as spending holds steady. Why is this?*

Slide 43 shows a significant growth in Alaska employment beginning in 2006, flattening between 2008 and 2011 and increasing by approximately 5% in 2012 (see also slide 34). The purpose of this slide is to benchmark employment changes in Alaska against other areas. We do not have 2012 comparative data for regions other than the lower-48. The top right panel shows employment growth in the rest of the US rose by a greater amount than the 5% we enjoyed in Alaska in 2012.

Chart 34 shows both Alaska spending (top right) and employment (bottom left) over time. The 5% employment growth between 2011 and 2012 is not matched by a similar increase in capital spending. I do not know the reason for this. I do note that we see the reverse happening between 2007 and 2008, with spending rising by a larger amount than employment. Finally, I'd note that I would not necessarily expect to see a match between capital spending and employment changes. Capital reflects spending on facilities and wells. A component of this will show up in Alaska employment, but some portion will not, as the spending (e.g., engineering, fabrication) may take place outside the state.

6. *Slide 45: Attractiveness of Investments: We talked a bit about the role of various factors such as prospectivity, stability, Internal Rates of Return. What other factors might be considered?*

   This slide begins the section on investment analysis. Slide 48 lists the measures or "metrics" we examined in our analysis. I believe these are the significant financial measures that companies consider when making investment decisions. In addition to the measures listed in Slide 48, companies will consider prospectivity, political and fiscal stability, contractual obligations, permitting and access, and environmental and regulatory issues. Companies will also consider whether the project and/or area fits with their overall corporate strategy and operations and their ability of management to adequately focus on the project and/or area. All of these issues matter, though they are not all readily quantifiable. This is why we focused our comparisons on the US, Canada, North Sea and Australia as they share many of the same "non-quantifiable" qualities and are areas in which many of the North Slope producers are active.

7. *Slide 47-52: ACES incumbents have very high IRR. Is it fair to say that this means it is almost impossible to NOT make money under the status quo? If so, why are projects being delayed?*

   The higher IRRs for ACES incumbents result entirely from the "buy-down" effect. Additional investment under ACES allows an incumbent to "buy-down" its tax rate on existing production. Under the ACES system a producer can earn those higher IRRs, but only if it reinvests in Alaska to buy down its tax rate. It cannot earn those returns if it chooses to distribute its profits to shareholders, which is vitally important to management, not to mention shareholders. In this sense, the profits (and associated higher IRRs) are somewhat "captive" and may not be viewed as being of same quality (i.e., comparable) to profits earned in other jurisdictions where no such strings are attached.

   I believe that this is one reason why projects "are delayed" or not started at all, even though the IRRs are so high. Higher IRRs are a good thing, ceteris peribus (meaning all else equal). The challenge here is that all else is not equal, as discussed above.

   Another reason is that IRR does not tell the whole story. IRR is just one measure that investors look at. IRR is an investment decision tool, but should not be used to compare mutually exclusive projects, only to decide whether a single project is worth investing in. Moreover, IRRs are not appropriate for comparing projects with different risk characteristics.

   It is also important to note that IRR assumes reinvestment of interim cash flows in projects with equal rates of return (the reinvestment can be the same project or a different project). Therefore, IRR overstates the annual equivalent rate of return for a project whose interim cash flows are reinvested at a rate lower than the calculated IRR. This presents a problem, especially for high IRR projects, since there is frequently not another project available in the interim that can earn the same rate of return as the first project.

   When the calculated IRR is higher than the true reinvestment rate for interim cash flows, the measure will overestimate, sometimes very significantly, the annual equivalent return from the project. The formula assumes that the company has additional projects, with equally attractive prospects, in which to invest the interim cash flows. This is likely to be the case for the high IRRs indicated for Alaska incumbents.

In short, IRR is one factor, but should not be viewed in isolation. IRR calculations that vary greatly from most other opportunities should probably be taken with "a grain of salt."

8. *Can you show us these IRR slides with a line for SB21 for both incumbent and new participants?*

Charts 62-66 show the same analysis as Charts 49-53 and include SB21.

9. *Slide 47: You indicate development costs of $16/bbl in Eagle Ford and $19 in Bakken. We have heard that development costs were significantly higher than that. A recent study using data from the North Dakota Industrial Commission in July 2012 found that the breakeven price for the "average" well in the Bakken formation is $80-$90/barrel, with an average decline of 40% in the first year. Can you explain the difference between "development costs" and "break-even price"?*

Breakeven price refers to the price of oil in the market that is necessary for an investor to "breakeven" on its investment. Here breakeven would include recovering costs, including the cost of capital. Development costs (indicated at $19/bbl in Slide 47) are the investment that one hopes to break even on. So when the ND Commission says the breakeven price is $80-90/bbl it means that oil prices must be in this range for a producer to plus recover its development costs, including its cost of capital (i.e., a return on capital), operating costs, royalties and taxes.

10. *Slide 49: The cash margins are 2017-2022. This cells looks are cash during the 1st 5 years of production (under SB21 tax would be lower). What would it look like during development when both Incumbents and New Producers have lost the ACES credits and deductions?*

The bottom left box shows margins per-barrel of production. It is cash generation divided by production. It's not possible to look at this metric during development as there is no production (i.e., denominator) during that period. Charts 59 and 60 do show producer cash flows under ACES and SB21. The first 5 years shown in these charts are the period of development.

11. *Slide 50: NPV-12 for ACES Incumbent is higher than NPV-12 for Bakken at prices below $120. Does this mean that using NPV as a measure tells us that under ACES, oil development on the North Slope is more profitable here than in North Dakota?*

Profit is an accounting concept while Net Present Value is an economic concept. A higher Net Present Value for a given project means that at the specified discount rate (in this case 12%) the project creates more value than a project with a lower Net Present Value. Slide 50 shows that the Net Present Value at a 12% discount rate creates more value to the ACES incumbent at prices below $120. As discussed above for slides 49-53 in the context of IRR, much of the higher NPV associated with the ACES incumbent is due to the tax buy-down on existing production. The ACES New Participant line shows a "break-even" NPV with the Bakken at about $100/bbl. The difference between these two reflects the impact of the buy-down for the incumbent.

The slide shows that ACES Incumbent has a higher NPV than Bakken until about $120/bbl, and a similar NPV to Eagle Ford at prices below $100/bbl. The New Participant has a higher NPV than Bakken until about $100/bbl, but a lower NPV than Eagle Ford at all price levels.

12. *Slide 52: NPV and IRR for ACES are higher than for Norway but reversed for Cash Margins for 2017-2022. What would this comparison look like if it included the years 2007-2017? And, what is the relative importance of NPV/IRR vs Cash Margins in decision-making?*

    The relationships seen in this chart should not change if one looked at 2007-2017 instead, with the potential exception of Canada, where fiscal terms did change during this period. The analysis is based on fiscal terms in place currently, which would apply going forward. NPV, IRR, and Cash Margins are all relevant metrics to producers. Which is more relevant is probably a good question for the producers. I do believe, however, that once a project's IRR is greater than the producer's hurdle rate, differences between IRRs across projects are likely to be viewed as less relevant for the reasons discussed above. I also expect that producers would view NPV as more relevant than IRR for purposes of comparison. Cash margins are important to producers, but they would not likely trump NPV on their own. Put another way, high cash margins, combined with negative NPV's would not lead to investment. PI is also relevant, and would be used to aide management rank projects where budgets or other constraints don't allow them to undertake everything at once, which is common.

13. *Slide 53: Same questions for Canada Oil Sands*

    See answer to question #12.

14. *Page 56: The Gross Revenue Exclusion is forever? Was there consideration of doing a 7 year exclusion as we did in the "middle earth" legislation last session?*

    Yes, consideration was given to a 7-year GRE as well as the life-of-recovery GRE proposed in SB21. Including the GRE for the life of recovery enhances the investment metrics relative to a 7-year GRE. It also encourages continuing investment and recovery from new fields and removes the potential that oil recovery may be "inefficiently" front loaded in a new project.

15. *Slide 57: Does the phrase "eliminates incentives for gold-plating" also mean "eliminates incentive to reinvest Alaskan profits in Alaska"?*

    The term "eliminates incentives for gold plating" refers to the fact that under ACES, the State effectively subsides the majority of capital spending for incumbent producers. As prices rise, that subsidy increases and can exceed 100% of the expenditure. This subsidy reduces a producer's incentive to efficiently manage costs. The term "gold plating" is a term of art that describes this situation.

    I don't think there is any way to read the phrase as also meaning "eliminates incentives to reinvest in Alaska." In my view SB21 will increase producer's incentives to invest in Alaska. Reducing the government's take on the producer's investment will leave the producer with a greater share of the profits from its investment. That greater share is what will enhance their incentive to reinvest (and continue to earn a greater share of the profits).

Along this line of reasoning, the State should not fear that producers will be encouraged to "take their profits elsewhere." If producers can keep a greater share of what they invest in Alaska, they will be encouraged to reinvest in Alaska, and less tempted to reinvest their profits elsewhere. The structure of SB21 enhances the producer's incentives to invest, and reinvest in Alaska relative to ACES.

16. *Slide 58: May we please see this chart extended to $200 oil?*

We have attached a revised Slide 58 showing prices up to $200/bbl as requested. In addition to the price extension, we have shown the figures for the 5-year period FY 2015 - 2019 rather than FY2014-18 as FY 2014 is a transition year.

17. *Slides 59 & 60: Under SB2l, the NPV of the governor's proposal is nearly identical for a new producer ($318m) as an existing producer ($319). It would seem that these numbers should not be quite so close, since the incumbent gets the value of their spending in years 1 as a 25% tax reduction, whereas the new producer must hold their Net Operating Loss credit for several years. Is it the 15% interest payment that makes up the difference?*

Yes, new producers who don't have a tax liability would not be able to deduct their losses during development under SB21. New producers can carry forward their losses, which are increased by 15% per year, and deduct them against their tax liability once production begins. The 15% increase helps to keep their NPV equivalent to that of the incumbent that has the ability to deduct the loss against current tax liabilities.

18. *How many taxpayers were filing for oil and gas credits on the North Slope for each of the years 2002-2012?*

On the following page is a table that shows the number of companies in each year that either (1) applied for tax credit certificates for credits earned under AS 43.55.023 or AS 43.55.025 on the North Slope, or (2) applied credits earned on the North Slope under AS 43.55.023, .024, or .025 against their tax liabilities in the specified years. This analysis captures the vast majority of companies on the North Slope earning tax credits applicable to the ACES production tax.

With respect to the analysis below, we note that the tax credit under AS 43.55.025 was implemented in 2003. Tax credits under AS 43.55.023 and .024 were implemented with PPT and subsequently expanded with ACES in 2006 and 2007, respectively. The expansion of credits available through PPT and ACES was a large contributing factor to the number of companies earning credits under these programs.

Number of taxpayers filing for oil and gas credits on the North Slope, CY 2002 - 2012	
Calendar Year	**Number of Companies**
2002	0
2003	0
2004	3
2005	1
2006	13
2007	20
2008	26
2009	33
2010	33
2011	30
2012*	36

*2012 totals subject to true-up filings due March 31, 2013
Above data reflects number of companies that either applied for tax credit certificates from activity on the North Slope or applied credits against their tax liability for oil and gas production on the North Slope
Includes credits under AS 43.55.023, .024, and .025.

19. *The comparisons used in the presentation rely on jurisdictions where much of the development is shale or gas. Can we please see some of the same comparisons using the locations worldwide where British Petroleum, ConocoPhillips and Exxon are producing and making new investments in conventional oil?*

Within OECD countries, these companies are making significant investments in conventional oil production in the North Sea, the U.S. Gulf and Offshore Eastern Canada. The analysis includes North Sea conventional production (both U.K. and Norway). We will look at adding comparisons with the U.S. Gulf and Eastern Canada offshore.

20. *Barry Pulliam testified that Alaska is viewed as unfriendly to business. Do you think that is an accurate view?*

Mr. Pulliam stated that Alaska is viewed as "a high tax, not always friendly place to do business." Mr. Pulliam did not say Alaska is "unfriendly to business." There would seem to be little doubt that Alaska is a "high tax" jurisdiction, particularly at current prices. Mr. Pulliam testified that Alaska has a very challenging physical environment on the North Slope, which is certainly not a "friendly" place to do business. He also mentioned the challenges associated with permitting new projects such as CD-5, a project that filed its first permits more than 5 years before receiving approval. He also stated that permitting practices by the State of Alaska itself were generally viewed positively by business. In addition, he mentioned the challenges associated with offshore development in the aftermath of the Gulf Horizon incident. In addition to these issues, producers are challenged by environmental lawsuits (e.g., Shell) that seek to delay or discourage development. These are all examples of how Alaska can be viewed as a place that is not always friendly to do business. DOR agrees with Mr. Pulliam's characterization.

21. *During his presentation of SB21 to the Legislature, Commissioner Butcher and Chair Micciche had a conversation about fairness being sharing profits of our oil with 1/3 to state, 1/3 to federal government and 1/3 to producers. Do you think a total government take of 2/3 is a reasonable goal?*

The administration is seeking a balance of providing enough profit to entice producers to bring Alaska's resources to market and simultaneously maintaining as much of those benefits as possible for Alaskans in accordance with our constitution. Attempting to capture too great a percentage of those benefits results in leaving resources in the ground as producers seek out better opportunities. With this balance in mind, the administration believes that the total government take should not exceed 2/3 of the profits from oil production. However, given investment alternatives available in other areas, this should be viewed as an upper limit on government take rather than a goal.

22. *What about contractual obligations to develop? We saw with Point Thompson that the duty to develop is enforceable. What do you think about the obligations/duty to develop as a factor in development decision-making?*

Contractual obligations certainly play a role in decision making. The primary lease term is really focused on prudent exploration and delineation. Upon unitization the State has a greater opportunity to leverage operators into development. While over the last decade unitization has been used as a tool to 'extend leases' this paradigm is fundamentally changing and development activities and obligations are becoming standard requirements in new unit approvals. The business decisions for 'explorers' is different than that of 'producers'. Successful exploration doesn't automatically result in development and production. If the economic environment isn't conducive to long term exposure of significant capital funds then developments aren't progressed. This is really a failed opportunity for the industry and the State.

23. *In terms of managing risk, are oil companies more concerned about risk at the low end or about high end?*

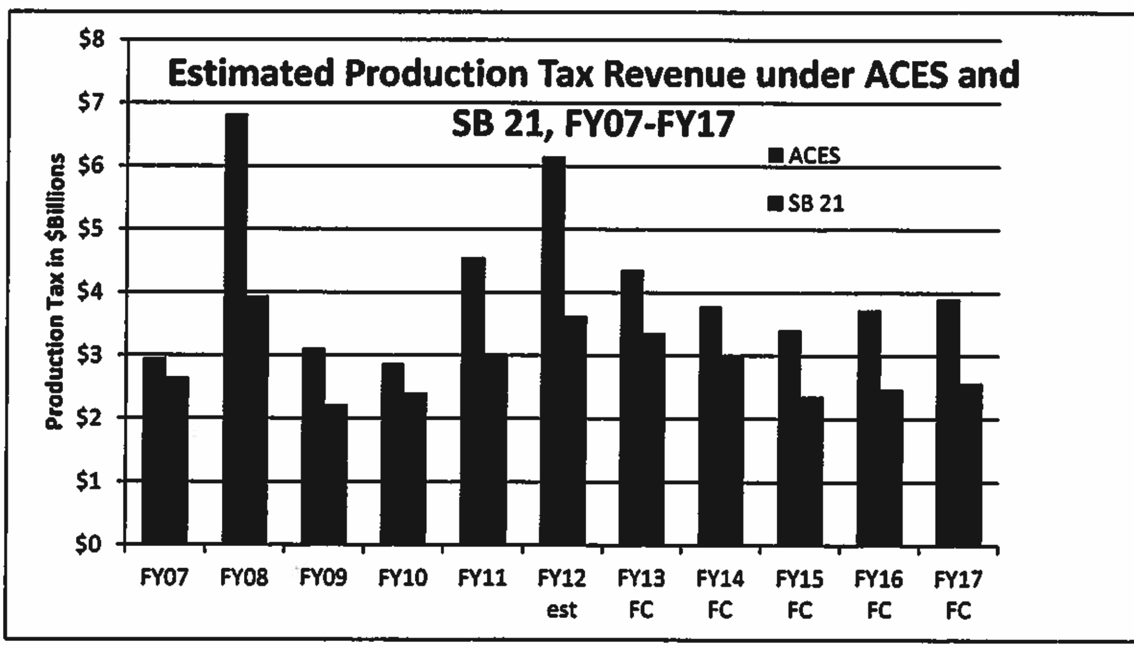
"Risk" is uncertainty. Uncertainty makes projects more "risky." Producers plan around a set of expected prices, but those expected prices may not prove to be correct. They also examine their economics at lower than expected prices (downside risk) and higher than expected prices (upside risk). They are concerned with both. They don't want to be in a situation where downside risk will cause a project will lose money. And, they will be less willing to take on this downside risk if their exposure to upside risk is limited. High progressivity removes much of the upside risk that might otherwise compensate for downside risk.

24. *What do we know about their hurdle rates or reasonable profits?*

We do not know what a specific company's hurdle rate or view of a reasonable profit is. Mr. Pulliam used a 12% discount rate in his analysis, which is widely viewed as reflecting producer's cost of capital in OECD countries. A hurdle rate would not be below the cost of capital. As an economic matter, we would expect producers to view a "reasonable" profit as one that is at least as good as its alternatives. Assuming all factors equal, if a producer can invest all the funds it has available and earn a 20% rate of return for example, it would likely view other opportunities as providing a reasonable profit as long as they also provided this type of return.

25. *In the 1/17/13 presentation "North Slope Oil Production History & Forecast" page 3 shows a forecast for General Fund Unrestricted Revenues for the Years 2012-2017. Can we please see that forecast (and history) for the years 2007-2017 under ACES, HB110 and SB21?*

Below is a chart showing the estimated production tax revenue under ACES and under SB 21, FY 2007 through FY 2017. What is not shown in this chart is the estimated savings from the state's general fund under SB 21 for not having to refund certain credits. From FY 2007 through FY 2012, that amount was approximately $1.2 billion. From FY 2013 through FY 2017, another savings of approximately $1.2 billion would be anticipated under SB 21, for a total savings over the 10-year period of about $2.4 billion.



I hope that you find this information helpful. I look forward to working together in our continuing efforts through the remainder of this legislative session.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosure: revised slide #58

Key Aspects of Administration's Proposal (cont'd)

- ➢ **Average Government Take Moves From Progressive to Relatively Neutral Under Proposal**