State of Alaska

Department of Revenue

Commissioner Bryan Butcher

DOR ~ ANGDA ~ Tax ~ Treasury ~ ARMB ~ AMBBA ~ APFC ~ PFD ~ AHFC ~ CSSD ~ AMHTA

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The Honorable Bill Stoltze
The Honorable Bill Thomas
Co-Chairs, House Finance Committee
Alaska State Legislature
Juneau, AK 99801

February 16, 2012

Re: Response to questions from House Finance Hearing on February 8, 2012

Dear Representatives Stoltze and Thomas:

The purpose of this document is to respond to the follow-up questions raised by the House Finance Committee meeting on February 8, 2012.
The requests/questions and responses follow.

1) **Provide a list of projects that we are aware of that are not included in our production forecast – what are the potential sources of additional oil?**

Our production forecast does not include any estimates for undiscovered oil, including future potential from the Alaska National Wildlife Refuge (ANWR), the National Petroleum Reserve-Alaska (NPR-A), the federal Outer Continental Shelf (OCS) or onshore lands within the state of Alaska. We exclude from our estimates production from most of the known heavy or viscous oil deposits; in fact we consider none of the approximately 20 billion barrels from the giant Ugnu deposit. We exclude 97% of the viscous/heavy oil from the large West Sak field, projecting roughly 137 million barrels recovery out of roughly 10 billion barrels in place. We also exclude more than 93% of the heavy oil at Schrader Bluff, projecting roughly 95 million barrels recovery out of over 2 billion barrels in place. Additionally, none of the known oil discoveries in the Federal Outer Continental Shelf, in fields such as Sivilluq, Kuvlum and Sandpiper, potentially totaling hundreds of millions of barrels of recoverable oil, are considered in the forecast. We also do not include any production from shale oil.

2) **Provide specifics about US energy demand history & forecast.**

U.S. energy demand grew at an average annualized rate of 0.9% from 2001 to 2007. U.S. energy demand fell by 7% from 2007 to 2009 during the U.S. economic contraction. Demand rebounded by 4% in 2010, and the Energy Information Administration (EIA) expects demand to have increased in 2011. The EIA projects U.S. energy demand to grow at an average annualized rate of 0.4% between 2010 and 2035.

U.S. energy imports grew at an average annualized rate of 2% from 2001 to 2007. Imports dropped by 14% from 2007 to 2009 and grew by 0.3% in 2010. The EIA expects energy imports to have increased in 2011.

Petroleum and other liquids demand remained flat from 2004 to 2007 at about 21 million barrels per day and fell by 9% to 19 million barrels per day from 2007 to 2009. Petroleum and other liquids demand grew 2% in 2010, and the EIA estimates petroleum and other liquids demand to have declined slightly in 2011. The EIA projects U.S. petroleum and other liquids demand to grow at an average annualized rate of 0.2% between 2010 and 2035.

Net petroleum and other liquids imports have fallen by 25% percent from 2005 to 2010. This is the first consistent decline in net petroleum and other liquids imports since the oil price spike of the late 1970s and early 1980s. The EIA expects net petroleum and other liquids imports to decline again during 2011.

3) Provide information about when production will come on line in other countries where capex is being spent.

The Energy Information Administration (EIA) expects petroleum and other liquids production to average 112.2 million barrels per day in 2035 from 86 million barrels per day average in 2010. The EIA anticipates about half of this 26.2 million barrels per day of production will come from OPEC countries, in particular Saudi Arabia and Iraq. Saudi Arabia, the largest producer and exporter of oil in 2010, is expected to increase its production through continued development of known fields such as the Manifa field, which is planned to produce almost a million barrels per day by 2014, and discoveries of new fields, such as the four new oil fields discovered in 2010. Iraq is the 4th largest holder of proven oil reserves but was only the 12th largest producer in 2009. The EIA expects Iraq's production will grow in the long term after the current legal and political uncertainties that are hampering near-term production growth are resolved.

The EIA expects the majority of the other half of production growth to come from the United States, Canada, Russia, and Brazil. U.S. oil production increases are expected to come from continued development of Bakken and Eagle Ford shale plays and new deepwater offshore fields such as Great White, Norman, Tahiti, Gomez, Cascade, and Chinook, which have recently come online or will in the near term. Canada's oil production growth is expected to come from the continued development of oil sands as production of its conventional oil declines. Most of Russia's current production comes from Western Siberia, but the EIA expects projects underway to tap resources in Eastern Siberia, the Caspian Sea, and Sahkalin will play an important role in Russia's future oil production. Brazil's offshore pre-salt deposits, such as the Tupi field discovered in 2007, are expected to make Brazil a major oil producer and exporter. The Tupi field sits 18,000 feet below the ocean surface and is estimated to hold 6.5 billion barrels of commercially recoverable reserves. The Tupi field began first production in 2010 and has been ramping up production since then. Other pre-salt deposits are currently under development and expected to come online in the coming years. These projects face many technical, financial, and regulatory hurdles.

4) Provide a list of experts who have participated in DOR price forecast sessions in the past few years.

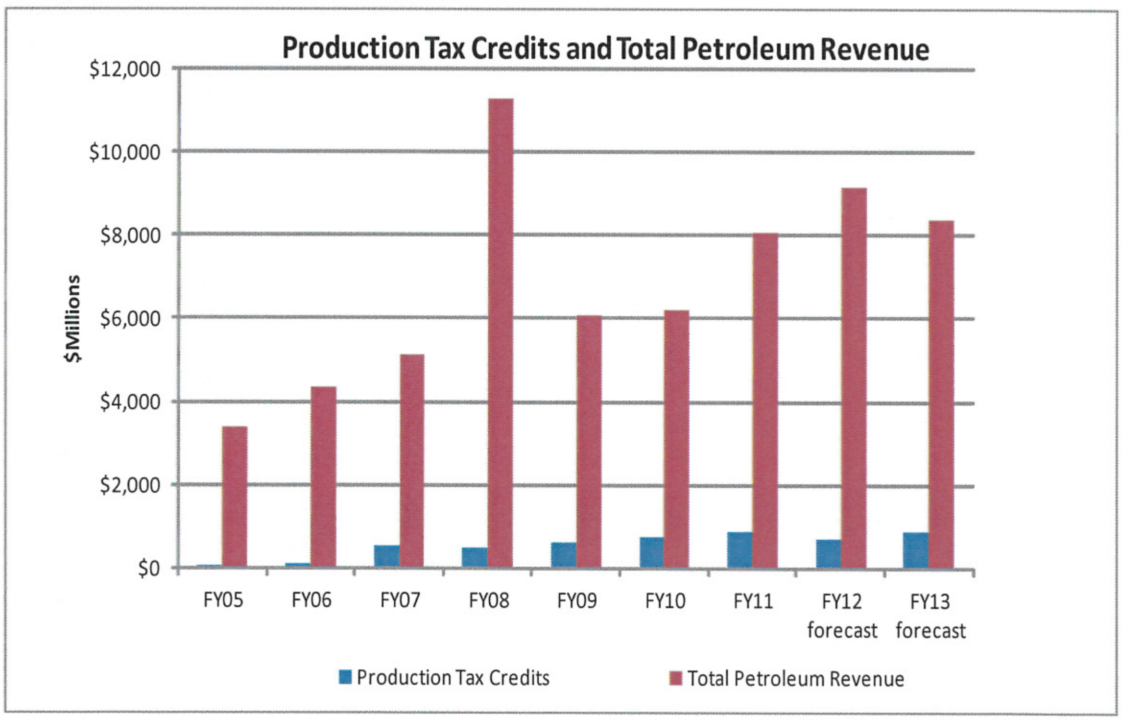
As presented in committee, participants at DOR oil price forecast sessions include many state economists, commercial analysts, financial analysts, and auditors from various agencies. Each session, we also invite speakers to present at our oil price forecasting sessions. These speakers primarily have an energy market background, and some have direct industry experience. At our Fall 2011 session, our speakers came from JP Morgan (and formerly the International Energy Agency), Platts Oil Assessment Service, and EIG Global Energy Partners. In previous sessions, we have had speakers from energy consulting firms, such as Black and Veatch and Strategic Energy and Economic Research (SEER). ConocoPhillips chief economist Marianne Kah presented to the group several years ago. We have asked her and BP chief economist Mark Finley to attend in recent years, but they have been unable to do so.

5) Provide total income received by the state over the time period for credits shown in slide 29.

See total production tax credits and total petroleum revenue table and graph on following page.

Production Tax Credits and Total Petroleum Revenue, FY 05 - FY 13

Status	Fiscal Year	Production Tax Credits	Unrestricted Petroleum Revenue	Restricted Petroleum Revenue	Total Petroleum Revenue	Delta - Petroleum Tax Credits and Petroleum Revenue
Actual	FY 2005	$11.0	$2,849.6	$545.5	$3,395.1	$3,384.1
Actual	FY 2006	$112.0	$3,699.2	$659.7	$4,358.9	$4,246.9
Actual	FY 2007	$549.0	$4,481.4	$660.3	$5,141.7	$4,592.7
Actual	FY 2008	$509.0	$9,956.0	$1,332.1	$11,288.1	$10,779.1
Actual	FY 2009	$641.0	$5,181.0	$888.2	$6,069.2	$5,428.2
Actual	FY 2010	$773.0	$4,912.9	$1,281.2	$6,194.1	$5,421.1
Preliminary	FY 2011	$863.0	$7,049.0	$1,041.2	$8,090.2	$7,227.2
Forecast	FY 2012	$725.0	$8,215.3	$962.0	$9,177.3	$8,452.3
Forecast	FY 2013	$875.0	$7,496.0	$895.9	$8,391.9	$7,516.9
TOTAL		**$5,058.0**	**$53,840.4**	**$8,266.1**	**$62,106.5**	**$57,048.5**



6) Why is ANS selling at higher prices than WTI?

Typically, WTI oil will sell at a higher price than ANS crude due to the fact the ANS crude is heavier, sour crude (more sulfur) which requires more refining. The reason for the recent shift in pricing can be linked to a few different factors. The production surge from North Dakota's shale oil resource and the increasing imports of Canadian crude is essentially flooding the oil market for WTI and reducing the price. With this glut of oil, pipelines are at capacity which forces lower value sales for WTI crude. Another contributing factor is that ANS crude is moved by tanker to West Coast refineries as opposed to WTI crude going by pipeline to Midwest refineries. The ANS oil competes in spot markets against other oil moved by tanker from overseas which enjoy higher pricing. Projections are that WTI prices will eventually climb closer to ANS crude with ANS price staying fairly steady.

7) Can we sell ANS to in-state refineries at WTI prices?

The State is unable to sell ANS to in-state refineries at WTI prices because the State is statutorily prohibited to sell its royalty in-kind oil for less than what the State would receive for royalty in-value. At today's prices, that would be at or near the ANS crude price of $117 minus marine transportation costs and the TAPS tariff.

8) Break out "pre-2009" credits on slide 29 by year.

See H FIN 2.8.12 Credits pre-2009 and break outs.pdf

9) Break out the credits by taxes in place – ELF, PPT, ACES.

See H FIN 2.8.12 Credits pre-2009 and break outs.pdf

10) APFC, please break out in which states/cities and major infrastructure the monies are invested.

See attached H FIN 2.8.12 APFC Infrastructure holdings.pdf and H FIN 2.8.12 Real estate holdings.pdf

I hope the answers fully address your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosures