

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 148 3211

DISTRIBUTION OF ANS OIL & GAS REVENUES BETWEEN THE PRODUCERS, ALASKA GOVERNMENTS AND THE US FEDERAL GOVERNMENT*

Production & Value Added By TAPS

	FY 1988	FY 1989	FY 1990	FY 1991	FY 1992	FY 1993	FY 1994	FY 1995
Note 1								
ANS West Coast Oil Price (\$/Bbl)	\$16.12	\$14.61	\$17.22	\$21.57	\$16.64	\$17.83	\$14.05	\$16.77
Transportation Cost to Market (\$/Bbl)	\$5.59	\$5.25	\$5.32	\$6.19	\$5.43	\$5.02	\$4.48	\$5.26
ANS Oil Wellhead Price (\$/Bbl)	\$10.53	\$9.36	\$11.90	\$15.38	\$11.21	\$12.81	\$9.57	\$11.51
ANS Oil & NGL Production (Million Bbl)	2,006	1,962	1,846	1,794	1,783	1,679	1,593	1,572
Oil & NGL Production Value (Million \$)	7,710.6	6,702.4	8,015.6	10,071.3	7,295.4	7,850.4	5,561.1	6,604.2
Note 2								
Production Costs (\$/Bbl)	4.00	3.80	3.70	3.50	3.50	3.31	3.07	2.97
Oil & NGL Production Costs (Million \$)	2,928.8	2,721.3	2,493.0	2,291.8	2,277.8	2,028.5	1,785.0	1,704.1
Note 1								
State Revenue + Muni Oil Prop (Millions \$)	2,175.4	1,936.2	2,347.6	2,998.7	2,213.2	2,322.4	1,646.3	1,974.7
Oil & Gas Production Tax (Inc Exp Credit)	804.0	680.2	977.1	1,289.8	898.1	968.6	675.4	772.5
Avg Economic Limit Factor (ELF)	0.792	0.785	0.938	0.926	0.926	0.927	0.917	0.905
Gross Oil & Gas Royalty	890.1	778.8	944.4	1,236.0	855.9	937.5	648.6	794.6
Property Tax State Share	96.4	89.9	83.4	82.8	78.3	63.3	63.1	58.2
Property Tax Muni Share	258.4	254.5	248.9	242.0	246.4	258.8	245.0	246.6
Corporate Petroleum Income Tax	126.4	132.8	93.8	148.1	132.4	94.1	14.2	102.8
Income Tax Production	13.1	32.0	(6.4)	50.6	41.0	10.4	(62.7)	32.1
Income Tax TAPS	113.3	100.8	100.1	97.5	91.4	83.6	76.9	70.7
Note 3								
TAPS tax allowance (Millions \$)	566.708	503.938	500.714	487.333	456.971	418.238	384.699	353.516
TAPS after tax margin	308.2	257.4	303.0	326.1	336.2	320.8	322.0	318.2
TAPS deferred return	558.7	515.1	463.7	419.7	363.4	296.9	245.5	203.7
Note 4								
Federal Revenue (Millions \$)	1,405.3	1,154.2	1,546.9	2,097.2	1,379.1	1,588.7	1,081.3	1,331.4
Percentage Federal	22.6%	22.0%	22.8%	23.3%	22.3%	23.2%	22.9%	23.1%
Note 5								
Company Net Revenue (Millions \$)	2,634.7	2,167.3	2,895.5	3,916.6	2,582.0	2,946.8	2,004.0	2,469.3
Percentage Company	42.4%	41.2%	42.8%	43.5%	41.8%	43.0%	42.4%	42.8%
State Revenue + Muni Property (Millions \$)	2,175.4	1,936.2	2,347.6	2,998.7	2,213.2	2,322.4	1,646.3	1,974.7
Percentage State & Local	35.0%	36.8%	34.6%	33.3%	35.8%	33.9%	34.8%	34.2%
Total Revenue Shared State, Federal, Company	6,215.4	5,257.6	6,790.0	9,012.6	6,174.3	6,857.9	4,731.5	5,775.5

* The Department of Revenue is in the process of reviewing the historical data with an eye to revising and improving the accuracy of these estimates.

Notes:

- Revenues, Prices, and Production taken from *Fall Revenue Source Book* Appendices.
Production Taxes include oil and gas severance, regulation and conservation and hazardous release Production Tax, Exploration Incentives and Royalties, 1996 thru 2005 from ShortCut History.
Total Alaska CIT is reduced by the percent oil volume produced in Cook Inlet (2%) to calculate a CIT for ANS.
Production Cost is taken from "How Much is Enough" by Richard Fineberg for FY 1988-FY 1996, Dept. of Revenue estimates for FY 1997-FY 2003. The Department will be evaluating production costs in the future.
- TAPS tax, after tax margin, and deferred return allowances from actual filings.
- Federal Revenue is calculated as 35% of the difference between production value and production cost (including state taxes on production) plus 80% of the TAPS tax allowance.
- 80% is the fed rate divided by the sum of the fed and state rates. The maximum marginal fed rate is 35%, the state rate is 9.4%.
- Company net revenue is calculated as production value less production costs less taxes on production plus the TAPS after tax allowance plus deferred return.

**SENSITIVITY WITH DIFFERENT
FOR FY 2007**

Sales Price (\$/Bbl)	\$48.00	\$49.00	\$50.00	\$51.00	\$52.00	\$53.00	\$54.00	\$55.00	\$56.00	\$57.00	\$58.00	\$59.00	\$60.00
Transportation Cost to Market (\$/Bbl)	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93	\$5.93
Wellhead Price (\$/Bbl)	\$42.07	\$43.07	\$44.07	\$45.07	\$46.07	\$47.07	\$48.07	\$49.07	\$50.07	\$51.07	\$52.07	\$53.07	\$54.07
ANS Production (oil and NGL) (Million Bbl)	0.843	0.843	0.843	0.843	0.843	0.843	0.843	0.843	0.843	0.843	0.843	0.843	0.843
Production Value (Million \$)	12936.9	13244.4	13551.9	13859.5	14167.0	14474.5	14782.1	15089.6	15397.1	15704.6	16012.2	16319.7	16627.2
Production Costs (\$/Bbl)	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Production Costs (Million \$)	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9	1998.9
State Revenue + Muni Oil Property (Millions \$)	3195.9	3261.0	3326.0	3391.0	3456.0	3521.1	3586.1	3651.1	3716.1	3781.2	3846.2	3911.2	3976.2
Severance Tax (Inc Haz Release)	894.3	915.3	936.3	957.4	978.4	999.5	1020.5	1041.5	1062.6	1083.6	1104.7	1125.7	1146.7
wtd avg severance tax rate	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%	14.70%
wtd avg Economic Limit Factor (ELF)	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
per bbl severance tax	\$2.91	\$2.98	\$3.04	\$3.11	\$3.18	\$3.25	\$3.32	\$3.39	\$3.46	\$3.52	\$3.59	\$3.66	\$3.73
Gross Royalty	1591.5	1629.9	1668.2	1706.6	1745.0	1783.4	1821.8	1860.2	1898.6	1937.0	1975.3	2013.7	2052.1
wtd avg royalty rate	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%
wtd avg field costs	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
per bbl royalty	\$5.18	\$5.30	\$5.42	\$5.55	\$5.67	\$5.80	\$5.92	\$6.05	\$6.17	\$6.30	\$6.42	\$6.55	\$6.67
Property Tax State Share	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00
Property Tax Muni Share	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2
Total property tax (production plus TAPS)	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2
property tax per bbl	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77	\$0.77
Total State Income Tax	\$472.00	\$477.60	\$483.20	\$488.80	\$494.40	\$500.00	\$505.60	\$511.20	\$516.80	\$522.40	\$528.00	\$533.60	\$539.20
Income Tax Production	430.1	435.7	441.3	446.9	452.5	458.1	463.7	469.3	474.9	480.5	486.1	491.7	497.3
State Income Tax TAPS	41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9
TAPS tax allowance (Millions \$)	209.37	209.37	209.37	209.37	209.37	209.37	209.37	209.37	209.37	209.37	209.37	209.37	209.37
TAPS after tax margin	259.83	259.83	259.83	259.83	259.83	259.83	259.83	259.83	259.83	259.83	259.83	259.83	259.83
TAPS deferred return	44.64	44.64	44.64	44.64	44.64	44.64	44.64	44.64	44.64	44.64	44.64	44.64	44.64
Federal Revenue (Millions \$)	2891.9	2976.7	3061.6	3146.5	3231.4	3316.2	3401.1	3486.0	3570.9	3655.7	3740.6	3825.5	3910.4
Percentage Total	25.3%	25.3%	25.4%	25.4%	25.5%	25.5%	25.6%	25.6%	25.7%	25.7%	25.7%	25.8%	25.8%
Company Net Revenue (Millions \$)	5364.0	5521.6	5679.3	5836.9	5994.5	6152.1	6309.8	6467.4	6625.0	6782.6	6940.3	7097.9	7255.5
Percentage Total	46.8%	47.0%	47.1%	47.2%	47.3%	47.4%	47.5%	47.5%	47.6%	47.7%	47.8%	47.8%	47.9%
State Revenue + Muni Share Oil Property (Mil	3195.9	3261.0	3326.0	3391.0	3456.0	3521.1	3586.1	3651.1	3716.1	3781.2	3846.2	3911.2	3976.2
Percentage Total	27.9%	27.7%	27.6%	27.4%	27.3%	27.1%	27.0%	26.8%	26.7%	26.6%	26.5%	26.4%	26.3%
Total Revenue Shared State, Federal, Compa	11,451.8	11,759.3	12,066.9	12,374.4	12,681.9	12,989.4	13,297.0	13,604.5	13,912.0	14,219.6	14,527.1	14,834.6	15,142.1
(If Revenue Shared is negative then state rev. are less than the total revenue losses by stat													

The transcript that follows includes the excerpted statements on the preceding pages, and a more complete transcription of the testimony before and after those excerpted statements.

House Resources Committee – March 13, 2006

(11:03 a.m.)

Tony Finizza: And, to illustrate this question that was raised earlier about is 25/20, could it look better for a producer, and in a funny kind of way it does. I'm saying... lets... no one's going to drill a one well program, but just say you did, and it was 20 million dollars - and that's the number I'm actually going to use for a well, 20 million - it's pretty expensive, but this is an expensive state and they're low product wells, etc. and eventually we have the high cost assumptions to make. If you did this well exploration - 20 million dollars - with a pattern I put in here under a status quo your negative cash flow would be roughly 20 million dollars. There's inflation in there that makes it higher, and then there's some tax sheltering that goes on. In the other cases, the PPT, you get to deduct capital as a credit, etc. and sell it and all that stuff. So naturally in actuality the producer or the explorer has less cash flow. Negative cash flow. And by this calculation, marginally better off with 25/20 than 20/20.

Rep. Samuels: Representative Berkowitz.

Rep. Berkowitz: Two questions with that. First of all could you walk us through those numbers, how you got there, just so I make sure I understand it, and secondly did you analyze at different rates than 20/20, 25/20 - did you do 30/20, or anything in the spread between?

Tony Finizza: Through the Chair, Representative Berkowitz, I personally didn't do anything but these two cases. They could be done and, we didn't think that was the boundaries we were allowed, we were presenting those possibilities. This is just to, the most likely PPTs that were being contemplated, I think is what... the way I looked at it. So, if in this, the way this is calculated by, first of all you have to imagine the pattern of capital, which I unfortunately haven't a picture of it. You put in the exploration capital over th's time period. It's not, it's like that picture I showed earlier. Like this. It's something like that, you put in...so the crescendo comes near the end of the 4 year period. You, in the 4th year, and then you take off of that, the... and you can deduct the capital expenditures being made, and then there's a tax credit for those expenditures being given. And so those all alter the cash flow there.

Rep. Samuels: Representative Gara.

Rep. Gara: Thank you. Doctor, just going from 20/20 to 25/20, and showing a slightly better cash flow for the explorer at 25/20, can we assume if we went to 30/20 or what Johnston recommended - 25/20 and then higher at a higher price, that the cash flow result would be maybe similar to 25/20 or.

Tony Finizza: Yes, what's working here is the fact that you're actually giving allowing capex expenditures to be in a sense deducted, someone else is helping pay for it, rather than in the status quo. So the higher the tax rate, you actually can shelter more of those expenditures. Now, the idea is not that this would be the end of the project, that this would bear fruit and you'd have with some probability development capital and production program, so you actually would find out if you looked at a total program that this pattern might not persist.

Rep. Samuels: I'm assuming that 100 would create a problem?

Tony Finizza: I'm sorry?

Rep. Samuels: I'm assuming that 100 would create a problem.

Tony Finizza: 100 and any credit would be a problem probably.

(11:11 a.m.)

Rep. Ramras: Representative Seaton?

Rep. Seaton: Yeah, trying to comprehend this. Is the factor that exploration is a negative loss all the time. I mean, you're never going to make money on exploration. When you're going to make money is if you discover something, and then you go into production. So if you want to stimulate exploration, exploration is always going to be a negative cash flow, so the more you subsidize that from the state, the more positive benefit there is. Although taxes aren't going to be paid until something gets into the development stage. Is that basically what we're talking about?

Tony Finizza: That's pretty accurate, yes.

Rep. Berkowitz: Mr. Chairman?

Rep. Ramras: Representative Berkowitz.

Rep. Berkowitz: Thank you very much. On that point then, where is it You've already established that a 100% tax rate is not effective. But at what point have we reached diminishing returns? Is it at 25, is it at 30, is it at 35? Where is that point?

Tony Finizza: Through the Chair, Representative Berkowitz. I... that is the question, what are diminishing returns. I... honestly, we don't think that any of these schemes, these programs would be onerous, but I think you have to... personally I would say is you have to err on the side of making sure you're not onerous, so you can't go too far here. I think this might become a little more clearer when we put the whole program together, rather than just the complete loss phase. And what you put in here has to be for other parts of the system as well.

Rep. Berkowitz: I understand, but if we're seeking that point that's, we need to know where diminishing returns is before we determine whether it's onerous. And it seems to me, knowing where diminishing returns exists is a number that we ought to have.

Tony Finizza: Representative Berkowitz, that is the 24 dollar, 64 dollar question. I don't think anyone honestly can answer that. There is no diminishing returns - no analysis that can be done in my opinion.

Rep. Berkowitz: But you could run a 30/20 number, you could run a 35/35 number, and we'd be able to compare based on this hypothetical.

Tony Finizza: I think this is what you'd be missing, and I think this might be clearer when we put the whole thing together. If you encourage too much exploration, you subsidize too much exploration, it may not be economic. You'd be losing money. The state bears a risk here too. If you encourage more exploration and prices don't warrant that as commercial exploration, you would be, you would have wasted money. So what's the measure we're trying to do here, it's not how much exploration you're gonna get but how much commercially economic exploration and I don't think I can help on that answer. I think it's more, but I don't.... I think the diminishing returns probably are... If I had a gut feel on this, I can't do it analytically, I think you're probably at it with this 25/20. I think it might be there, but that's gut feel.

Rep. Samuels: Representative Crawford, Kerttula and then Gatto.

Rep. Crawford: Thank you Mr. Chairman. My question for you is way more basic. And that's the efficacy of going to a profits based tax. It seems to me that when you change from a production based tax to a profits based tax that you're leaving it open to manipulation of what a profit is, and what your opinion of what, you know, is this a right thing to do, to go to a profits based tax rather than a severance tax based on production.

(11:17 a.m.)

Rep. Samuels: Representative Kerttula.

Rep. Kerttula: I'm not sure I'm going to be even able to understand it, but I wanted to ask the question. But back to the 25/20 or higher, is it because you're going to be able to get the deduction from the credits on the higher number. Is that what it is?

Tony Finizza: Yup.

Rep. Kerttula: What if you went then, to 35/30. What if you're giving even more deductions and credits, wouldn't that also commensurately make it so that the higher tax rate was acceptable?

Tony Finizza: Well, the arithmetic would show that in this particular example. The question is then, would you be willing, as a state, to run the risk of running a big loss at that level. In a failed exploration program. I think when I put this together, it might be clear, and we may not get to that type of clarity, but I'll try.

Rep. Samuels: We'll try to keep moving on here because you might get to answer some of these questions. Representative Gatto.

Rep. Gatto: I'll pass.

Rep. Samuels: Thank you. Representative Gara.

Rep. Gara: Thank you. Just a follow up so I'm clearer in your answer to Representative Berkowitz. He asked you, you said at 25/20, you might be, that might be the point where you start maximizing revenues before you start hitting diminishing returns. Is that, did I understand that fairly?

Tony Finizza: I said that I had a gut reaction that that was a point of diminishing returns, and that's... for an exploration, yup. I wouldn't think that you would have to go further than that to encourage or, you wouldn't, and then take a greater risk yourself.

Rep. Gara: Am I wrong in assuming... If I'm looking for the point where's you've started to maximize your long term state revenue but before you start losing money because you're taxing too much - that's your gut reaction on 25/20 or am I missing?

Tony Finizza: That's my gut reaction, yeah.

Rep. Gara: Thank you.

(12:55 p.m.)

Rep. Samuels: Representative Ramras.

Rep. Ramras: Thank you Mr. Chairman. Let me back it off just a little bit from, in, [indiscernible] on this chart. Somewhere between... your suggestion is that at 20/20 and at 25/20 you don't disturb industry's evaluation of whether investment in Alaska is economic or not. And, that was at the beginning when you said the models were at a 30 dollar stress price, 40 dollar base price... I asked you about 50, you said well the

model's not necessarily symmetric in that way and that it's against that forecasters have been burned over time. So we're... What this suggests is that if you clear the hurdle of the economic decisions of industry - of whether a 25 million barrel or a 500 million barrel field are economic or not - if you clear that hurdle, then if you go into this progressivity, whether it's .2, or .25 or .3 or .35, then you're sharing in the windfall profits after that, but you have kinda cleared the space of where the oil companies in their board rooms are making their decisions of whether or not it's economic to invest in Alaska.

Barry Pulliam: Yeah, I mean, you're doing... any tax system you put into place they will evaluate with exactly that in mind. Having something like this, is a different one they would have to evaluate. But what it would do is that they would know, at lower levels, whatever level below this threshold you put in here, whether it be 35 or 40 or 45, whatever, that the rate would be... there would be no increase in the marginal rate.

Rep. Ramras: Alright, again, an IRA. If any of us at this table had an IRA, , our retirement, that we're trying to project... You know they say that at age 20 you can be aggressive and go all in stocks. And at age 40 it's a mix of stocks and bonds and at age 60, you better be real careful with your nest egg because you gotta stretch out. So if we're selecting a place on this spectrum of prices per barrel and this is our nest egg, we cannot jeopardize it at all. The whole point of PPT is to incentivize exploration and more investment dollars coming to Alaska to keep the pipe full. Where along that spectrum are we safe? 30 as a stress price? 40 as a base price? Some of your models went as high as 45. What's the safe number where we're behaving like a 60 year old protecting the nest egg of their IRA. Where's that number along the spectrum?

Barry Pulliam: Our view, we sat down with the administration folks who came up with the PPT, Dr. Van Meurs, and considered those very questions when he was first submitting his recommendations. And in our view certainly the 20/20 was very safe. Very safe. The 25/20 we even thought was safe.

Rep. Ramras: I'm sorry, Mr. Chair, I meant a price per barrel of oil, for economics...

Barry Pulliam: Oh, I'm sorry...

Rep. Ramras: ...not the tax program, but the price per barrel of oil. 30 as a stress, 40 as a base, where do we clear the hurdle on the other side where we're inside of all the board room projections, along their bell curve.

Barry Pulliam: Well, I think in that 35-40 range, is about right. But, you also need, I think, to... I mean, that's a long term average, within that you're going to have prices lower, and prices higher. So, the notion behind the kind of system that people have talked about, the progressivity, is that when prices are higher, you share in that. And when they're lower you share in that as well. So, I think as far as an average, what people are, what Dr. Finizza has indicated, that people are looking at today, to make this investment decisions - 35-40, that clears the hurdle for investment decisions. Now, do they think that that's... they're hoping for some upside, right? And that's one of the reasons they do it. As part of that analysis, they're looking at the upside. They may not think that the upside's there with 100% certainty and certainly they, it's... they discount it... but they make it because there is a potential for upside, there is a pretty good chance they think at 40 I'm going to do well on this, and down at 30 I'm not going to lose my shirt. But boy I'd sure like that upside. We all would like the upside, that's what we're talking about here. And how do you balance that between the state getting a part of the upside, and investors getting a part of the upside? And, it's a, it is a balance, if you make it too steep, then investors will look at that, they'll plug that into their formulas, and they'll say, okay, what am I going to want to walk away with... if oil goes to \$80 dollars a barrel. Because that's part of my decision making, and there's some chance it's going to go to 80 - what's it going to look like for me? Well, if you're going to take everything away from me above 40 dollars a barrel, you're not that attractive. If you're going to take a little bit more away from me as price goes up... that's okay. That's pretty consistent with what happens around the world. If you take too much away from me, you get less attractive. So, it's striking that balance, and again, if you look at this in light of the work that was done by Dr. Van Meurs and our review of it, we certainly thought that the 25/20 would not result in rates, in tax rates or government take that would be discouraging at price levels that you

might see, and even as you get on the upside, certainly wouldn't be discouraging. You're not taking away too much of the upside. And, consistent with what Mr. Johnston has said, even as you get into the very high prices, taking away... having a higher increment on that, is not going to be discouraging either. Just don't wanna get too high. I would say, and then [indiscernible] in general to the extent, again, and give a big caveat here, Dr. Finizza and I are not fiscal system planners, and as you've heard from some, we are mere economists and so, approach this with a... approach it cautiously. Higher taxes, in general, are... you have to find the balance, that's the key. You are out there as a state trying to... your goal, I think, is and should be, to maximize the value of this resource for the state of Alaska. And that involves finding a balance between having a rate that is high enough to keep people interested here, not so high that you start to lose a lot of interest. Losing a little bit of interest may not be bad, depending on what the total revenue pie is... **But you don't want to lose a lot of interest and as, as economists who have worked with forecasting, and looking at decision-making, I think our view would also be you don't want to be in a position where you're... you've calculated that you've taken every last penny of what's available. You want to leave something... you want to make it attractive. You want to leave enough to make it attractive. Keep people real interested. We don't think the 25/20 goes beyond that at all, and then with some increment above that, we think it still stays real attractive. Now, in thinking about the sliding scale. What would you do? I think our view in general would be if you're thinking about starting it lower, have a lower increment. If you're thinking about starting it higher, have a higher increment. I think that's probably... just as a general thing. Otherwise, if you start real low and have a real high increment, you go pretty steep. So, that would be our...**

Rep. Samuels: Representative Gatto.

Rep. Gatto: Just looking at the maximum prices you have here... If we explode this view and say oil is above 80, 100, let's just say... Does your chart essentially stop at 80 and say we no longer incrementalize (sic) at x dollar?

Barry Pulliam: Our charts stop at 80, the calculations can easily be extended beyond 80...

Rep. Gatto: I'm looking for your suggestion... Because these are your charts. Did you mean it to stop at 80?

Barry Pulliam: Yes.

Rep. Gatto: Or did you mean it to say, beyond 80, count every 5 dollars and extend it...

Barry Pulliam: Extend it like this... you might... you know, there could become a level where you would cap it, and say we're just not gonna... we could have some cap out there. But at over 80 dollars here, these are real prices, that's you're looking, if you have 80 dollars real prices, you know, out 20 years, you're over 100 dollars a barrel so... it's a... this allows for some pretty healthy pricing in here.

Rep. Samuels: Representative Seaton.

Rep. Seaton: Thank you. And, so just to be clear, within these scenarios, are there any of them that you've projected here that you think are, from your standpoint, in your analysis, that would be detrimental to investment in the industry here in Alaska?

Barry Pulliam: No. Looking at these, I don't see any that would be, that would fall into the detrimental area. I put, as I look at this, I try to put these into a historical context - look at what the rates have been at given price levels. And as you look at those, even as you look at the highest one of these that you'd have, which would be the 35 threshold with a .35% increment, you see as you... you know, when you're at 40 dollar prices there your tax rate is only 11.4%. That's at a higher price level, that's a lower percentage than your historical average. You start to ratchet up beyond there, but you have some pretty high prices that those are associated with. So, there might be a little bit of stuff around the margin that

would look at that and say that's not of interest. I don't think for the majority of what you have that would be the case. But, I can see reasons why you wouldn't do that either. You might have a more cautious approach.

(1:10 p.m.)

Barry Pulliam: If I could answer, Chairman Ramras, also... the... we are assuming here that, as with all tax systems, you try and anticipate the future, and tailor your system as best you can. But if the future turns out to be different than what you expect, you can alter it. And should alter it to make sure you strike the right balance. If you told me, however, that I cannot change this tax in the future, this decision is one that I have to stick with for a long time, then... or, at least this is one... this is taxes. Once you make a decision you're not going to be able to raise them. You may be able to lower them, but if you're constrained against raising them, I think that should enter into your calculation of where along this you go to the less aggressive end or the more aggressive end. If you can't raise them realistically in the future... if you find out that you were wrong, then you would be better off to have... to be on the more aggressive side, knowing that you could come back and lower them. If that's not a constraint, then if you've been too conservative at the outset, you can revisit it and look at it, and do it again. But I am mindful of the fact that just as a... it is hard as legislators, I know, to raise taxes. It's easier to lower them than it is to raise them.

House Resources Committee – February 23, 2006

(2:10 p.m.)

Rep. Gara: I want to assess the difference between the 25 percent tax plan that you had presented to me and others, and the 20 percent tax plan that is before us now. Two of the main differences was the 20 percent credit/25 percent tax and the other was the effective date of January 1st. And when we spoke, you said with those provisions, with the 25/20 and Jan 1st effective date that would put us in a strong position competitively and provide a fair return to the state. With a Jan 1st effective date do you still think that that would be a fair assumption with the 25/20 plan, in your mind?

Dr. Pedro Van Meurs: The 25/20 and the 20/20 both are very competitive systems, that you could see from the investment. If I say competitive, it means that both systems would be considered quite attractive by investors. Consequently that is an important factor. What is of course the concept is when would the tax actually start. Obviously an early start date, a retroactive start date starting in January would be an extra year of income for the state. Typically around the world, taxes start after they have been approved, but sometimes you can backdate them. The current law kind of contemplates that it starts on the first of July, so consequently that is what the bill contains.

Rep. Gara: When we discussed it last week or the week before, I think your position was that the January 1 start date wouldn't really impact the competitiveness. Still be appropriate from the competitiveness and revenue standpoint. Is that still a fair assumption if we decided to go back and amend the bill to go back to that [to the Jan 1st start date]

Dr. Pedro Van Meurs: That is absolutely true. Whether you start the tax on Jan 1 or July 1 really has no impact on the competitiveness of the system. Because new investors would look at new investments and would not even have to pay tax for now, for awhile. So consequently whether you have a July or Jan start day, that would not have impact on new investors. So would be equally, say, attractive either way. The only difference between the Jan 1 and the July 1 start date is that of course it has enormous impact on existing production. So as far as existing production, you would have 6 months more of revenues if you moved the date back to Jan 1st of this year.

Rep. Kerttula: If we can allow incentives, and we've got a US Supreme Court case right now, so that's going to be a good question. But if we can... are allowed to break them apart, then your recommendation is that we break apart the legacy versus the newer fields that we want to incentivize?

Daniel Johnston: Through the Chair, Representative Kerttula. Yes, that's got its problems too, no doubt about that. But in my mind at least, I've got a lot of experience and a lot of comfort with countries that do things that way. Quiet a few. And Pakistan has onshore terms, and then they have to pay Pakistan 1, Pakistan 2 and Pakistan 3 terms for different types of areas. Algeria has Zone A, Zone B and Zone C as I recall. And then you have offshore terms and you have onshore terms and some countries have some special and different terms for gas than for oil. That's what I'm comfortable with and that's what I've seen.

Rep. Kerttula: That was my last question was... Are you aware of any other country that allows that dollar for dollar kind of set off for the oil or, I mean, the gas against the oil or any other manner - one against the other like that. That confuses me to allow that.

Daniel Johnston: Through the Chair, Representative Kerttula. I think I understand the question... dollar-for-dollar credits...

Rep. Kerttula: Right.

Daniel Johnston: But you're talking about dollar-for-dollar credits from oil expenditures against gas profits?

Rep. Kerttula: Right, or vice-versa, the gas against the oil.

Daniel Johnston: I'm sure that they do exist and specific examples of, you know, where you have the 2 different types of production and the credits can "cross the fence" as we say. Many many countries apply and allow either credits or the cousin to credits that we call "uplifts" - investment allowances and things like that. But when governments have different terms for gas as they often do - and quite often they do - the statistics that I showed, and I know there were a lot of those, the world average government take even right now is probably 67 or 70 depending upon how you calculate it. Wood Mackenzie aggregates their statistics a little bit differently too [inaudible] but in the Wood Mackenzie world average government take statistic from their study was I think 71%. The world average statistic for gas take is maybe 61. When you have a different tax system for one versus the other, then you've got problems.

Rep. Kerttula: Thank you.

DISTRIBUTION OF ANS OIL & GAS REVENUES BETWEEN THE PRODUCERS, ALASKA GOVERNMENTS AND THE US FEDERAL GOVERNMENT*

Production & Value Added By TAPS

	FY 1988	FY 1989	FY 1990	FY 1991	FY 1992	FY 1993	FY 1994	FY 1995
Note 1								
ANS West Coast Oil Price (\$/Bbl)	\$16.12	\$14.61	\$17.22	\$21.57	\$16.64	\$17.83	\$14.05	\$16.77
Transportation Cost to Market (\$/Bbl)	\$5.59	\$5.25	\$5.32	\$6.19	\$5.43	\$5.02	\$4.48	\$5.26
ANS Oil Wellhead Price (\$/Bbl)	\$10.53	\$9.36	\$11.90	\$15.38	\$11.21	\$12.81	\$9.57	\$11.51
ANS Oil & NGL Production (Million Bbl)	2,006	1,962	1,846	1,794	1,783	1,679	1,593	1,572
Oil & NGL Production Value (Million \$)	7,710.6	6,702.4	8,015.6	10,071.3	7,295.4	7,850.4	5,564.4	6,604.2
Note 2								
Production Costs (\$/Bbl)	4.00	3.80	3.70	3.50	3.50	3.31	3.07	2.97
Oil & NGL Production Costs (Million \$)	2,928.8	2,721.3	2,493.0	2,291.8	2,277.8	2,028.5	1,785.0	1,704.1
Note 1								
State Revenue + Muni Oil Prop (Millions \$)	2,175.4	1,936.2	2,347.6	2,998.7	2,213.2	2,322.4	1,646.3	1,974.7
Oil & Gas Production Tax (Inc Exp Credit)	804.0	680.2	977.1	1,289.8	898.1	968.8	675.4	772.5
Avg Economic Limit Factor (ELF)	0.792	0.785	0.938	0.926	0.926	0.927	0.917	0.905
Gross Oil & Gas Royalty	890.1	778.8	944.4	1,236.0	855.9	937.5	648.6	794.6
Property Tax State Share	96.4	89.9	83.4	82.8	78.3	63.3	63.1	58.2
Property Tax Muni Share	258.4	254.5	248.9	242.0	248.4	258.8	245.0	246.6
Corporate Petroleum Income Tax	126.4	132.8	93.8	148.1	132.4	94.1	14.2	102.8
Income Tax Production	13.1	32.0	(6.4)	50.6	41.0	10.4	(62.7)	32.1
Income Tax TAPS	113.3	100.8	100.1	97.5	91.4	83.6	76.9	70.7
Note 3								
TAPS tax allowance (Millions \$)	566.708	503.938	500.714	487.333	456.971	418.238	384.699	353.518
TAPS after tax margin	308.2	257.4	303.0	326.1	336.2	320.8	322.0	318.2
TAPS deferred return	558.7	515.1	463.7	419.7	363.4	298.9	245.5	203.7
Note 4								
Federal Revenue (Millions \$)	1,405.3	1,154.2	1,546.9	2,097.2	1,379.1	1,588.7	1,081.3	1,331.4
Percentage Federal	22.8%	22.0%	22.8%	23.3%	22.3%	23.2%	22.9%	23.1%
Note 5								
Company Net Revenue (Millions \$)	2,634.7	2,167.3	2,895.5	3,916.6	2,582.0	2,946.8	2,004.0	2,469.3
Percentage Company	42.4%	41.2%	42.6%	43.5%	41.8%	43.0%	42.4%	42.8%
State Revenue + Muni Property (Millions \$)	2,175.4	1,936.2	2,347.6	2,998.7	2,213.2	2,322.4	1,646.3	1,974.7
Percentage State & Local	38.0%	36.8%	34.6%	33.3%	38.8%	33.8%	34.8%	34.2%
Total Revenue Shared State, Federal, Company	6,215.4	5,257.6	6,790.0	9,012.6	6,174.3	6,857.9	4,731.6	5,775.5

* The Department of Revenue is in the process of reviewing the historical data with an eye to revising and improving the accuracy of these estimates.

Notes:

1 Revenues, Prices, and Production taken from *Fall Revenue Source Book Appendices*.

Production Taxes include oil and gas severance, regulation and conservation and hazardous release Production Tax, Exploration Incentives and Royalties, 1996 thru 2005 from ShortCut History

Total Alaska CIT is reduced by the percent oil volume produced in Cook Inlet (2%) to calculate a CIT for ANS.

Production Cost is taken from "How Much is Enough" by Richard Fineberg for FY 1988-FY1996, Dept. of Revenue estimates for FY 1997-FY 2003. The Department will be evaluating production costs in the future

2 TAPS tax, after tax margin, and deferred return allowances from actual filings

3 Federal Revenue is calculated as 35% of the difference between production value and production cost (including state taxes on production) plus 80% of the TAPS tax allowance

4 80% is the fed rate divided by the sum of the fed and state rates. The maximum marginal fed rate is 35%, the state rate is 9.4%.

5 Company net revenue is calculated as production value less production costs less taxes on production plus the TAPS after tax allowance plus deferred return.

DISTRIBUTION OF ANS OIL & GAS REVENUES BETWEEN THE PRODUCERS, ALASKA GOVERNMENTS AND THE US FEDERAL GOVERNMENT*

Production & Value Added By TAPS

	FY 1996	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005
Note 1										
ANS West Coast Oil Price (\$/Bbl)	\$17.74	\$20.90	\$15.86	\$12.73	\$23.27	\$27.85	\$21.78	\$28.15	\$31.74	\$43.44
Transportation Cost to Market (\$/Bbl)	\$5.14	\$4.50	\$3.95	\$4.26	\$4.21	\$5.81	\$4.98	\$4.88	\$4.96	\$4.51
ANS Oil Wellhead Price (\$/Bbl)	\$12.60	\$16.40	\$11.91	\$8.47	\$19.06	\$22.24	\$16.80	\$23.27	\$26.78	\$38.92
ANS Oil & NGL Production (Million Bbl)	1.474	1.404	1.275	1.184	1.035	0.991	1.004	0.991	0.980	0.917
Oil & NGL Production Value (Million \$)	6,778.9	8,404.3	5,542.6	3,598.6	7,200.4	8,044.6	6,166.5	6,417.1	9,579.2	13,032.4
Note 2										
Production Costs (\$/Bbl)	3.09	3.67	4.24	4.67	5.10	5.96	6.44	6.44	6.50	6.70
Oil & NGL Production Costs (Million \$)	1,682.5	1,880.7	1,973.2	1,984.1	1,926.7	2,154.4	2,359.3	2,328.7	2,325.1	2,243.3
Note 3										
State Revenue + Muni Oil Prop (Millions \$)	2,011.7	2,429.5	1,620.7	1,144.9	1,955.1	2,324.4	1,621.5	2,095.6	2,412.9	3,223.5
Oil & Gas Production Tax (Inc Exp Credit)	754.2	915.2	576.7	351.4	664.5	696.4	462.8	571.3	621.7	796.1
Avg Economic Limit Factor (ELF)	0.8847	0.8422	0.8176	0.7404	0.8817	0.6429	0.5975	0.5519	0.5322	0.530
Gross Oil & Gas Royalty	819.7	1,007.2	603.3	403.4	898.2	1,100.9	762.8	1,146.4	1,296.1	1,754.5
Property Tax State Share	53.9	51.1	49.1	47.4	45.3	42.5	40.1	44.3	43.5	42.5
Property Tax Muni Share	245.0	240.5	231.6	226.6	217.0	214.1	213.0	212.8	212.5	211.2
Corporate Petroleum Income Tax	139.0	215.5	180.1	116.1	130.2	270.5	142.7	120.9	239.0	419.2
Income Tax Production	76.4	163.1	116.6	76.1	90.7	230.0	101.2	79.5	198.3	377.9
Income Tax TAPS	62.6	52.4	43.5	39.9	39.4	40.4	41.5	41.4	40.8	41.3
Note 4										
TAPS tax allowance (Millions \$)	312.900	262.094	217.331	199.651	197.131	202.201	207.427	206.771	203.922	206.702
TAPS after tax margin	309.1	290.0	275.2	250.6	243.2	248.5	255.1	257.2	253.2	256.9
TAPS deferred return	153.7	99.0	48.9	47.2	50.1	51.1	51.2	47.1	46.2	45.6
Note 5										
Federal Revenue (Millions \$)	1,358.9	1,661.0	871.1	338.0	1,333.0	1,423.9	942.0	1,577.3	1,671.9	2,627.8
Percentage Federal	23.1%	23.2%	21.2%	16.0%	23.1%	22.3%	21.9%	23.9%	24.1%	25.0%
Note 6										
Company Net Revenue (Millions \$)	2,521.6	3,084.4	1,619.0	629.0	2,476.0	2,643.7	1,747.4	2,926.5	3,472.7	5,247.0
Percentage Company	42.8%	43.0%	39.4%	29.8%	43.0%	41.4%	48.8%	44.3%	44.8%	46.4%
Note 7										
State Revenue + Muni Property (Millions \$)	2,011.7	2,429.5	1,620.7	1,144.9	1,955.1	2,324.4	1,621.5	2,095.6	2,412.9	3,223.5
Percentage State & Local	34.1%	33.9%	39.4%	54.2%	33.9%	36.4%	37.6%	31.8%	31.1%	28.5%
Total Revenue Shared State, Federal, Company	5,892.2	7,174.8	4,110.8	2,111.9	5,764.2	6,392.0	4,310.9	6,599.5	7,757.5	11,298.3

* The Department of Revenue is in the process of reviewing the historical data with an eye to revising and improving the accuracy of these estimates.

Notes:

1 Revenues, Prices, and Production taken from *Fall Revenue Source Book Appendices*.

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4 80% is the fed rate divided by the sum of the fed and state rates. The maximum marginal fed rate is 35%, the state rate is 9.4%.

5 Company net revenue is calculated as production value less production costs less taxes on production plus the TAPS after tax allowance plus deferred return.

Federal, Company and State Revenue Shares under the 2005 ELF Based Severance Tax System & HB63 Using FY 2007 Production Volumes from the Spring 2006 Revenue Sources Book

Sales Price (\$/Bbl)	Forecast Price \$53.60	\$10	\$12	\$14	\$16	\$18	\$20	\$22	\$24	\$26	\$28	\$30	\$32	\$34	\$36	\$38
Costs																
Avg Trans To Market	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20	\$6.20
Wellhead Price (\$/Bbl)	\$47.40	\$3.80	\$5.80	\$7.80	\$9.80	\$11.80	\$13.80	\$15.80	\$17.80	\$19.80	\$21.80	\$23.80	\$25.80	\$27.80	\$29.80	\$31.80
Volumes																
Oil production (millions bbls/day)	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792	0.792
NGL production (millions bbls/day)	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033
ANS Production (oil and NGL) (Million Bbl/Yr)	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2	301.2
Production Value (Million \$)	14275.2	1143.1	1745.5	2347.9	2950.3	3552.7	4155.1	4757.5	5359.8	5962.2	6564.6	7167.0	7769.4	8371.8	8974.2	9576.6
Production Costs (\$/Bbl)	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32	\$8.32
Production Costs (Million \$)	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9	2505.9
Severance Taxes																
NGL Severance Tax	19.83	1.55	2.38	3.22	4.06	4.90	5.74	6.58	7.42	8.26	9.10	9.93	10.77	11.61	12.45	13.29
Gas Severance Tax	3.10	0.25	0.38	0.51	0.64	0.77	0.90	1.03	1.16	1.29	1.43	1.56	1.69	1.82	1.95	2.08
Hazardous Release	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59	7.59
Oil Severance Tax with ELF Based Severance	953.4	107.7	128.5	149.3	170.1	190.9	211.7	232.5	253.3	274.1	294.9	315.7	336.5	357.3	378.1	398.9
Oil Severance Tax with HB63	2553.1	63.3	109.6	165.4	221.3	277.1	333.0	388.8	444.7	500.5	556.4	612.2	668.1	723.9	779.8	835.6
Per Barrel Oil & NGL Severance Tax																
With Aggregation	\$3.17	\$0.36	\$0.43	\$0.56	\$0.69	\$0.82	\$0.95	\$1.08	\$1.22	\$1.35	\$1.48	\$1.61	\$1.74	\$1.87	\$2.01	\$2.14
Under HB63	\$8.48	\$0.21	\$0.36	\$0.56	\$0.77	\$0.92	\$1.07	\$1.34	\$1.65	\$1.98	\$2.35	\$2.74	\$3.16	\$3.62	\$4.10	\$4.62
Royalty																
Gross ANS	1841.8	204.2	279.3	354.3	429.4	504.5	579.6	654.7	729.8	804.9	880.0	955.1	1030.2	1105.3	1180.4	1255.5
per bbl royalty	\$6.11	\$0.68	\$0.93	\$1.18	\$1.43	\$1.67	\$1.92	\$2.18	\$2.43	\$2.68	\$2.93	\$3.18	\$3.43	\$3.68	\$3.93	\$4.18
Property Tax																
State Share (ANS only)	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Muni Share (ANS only)	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2	204.2
Total property tax (production plus TAPS)	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2	238.2
Property tax per bbl	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79	\$0.79
Total Severance, Royalty, State and Local Property taxes																
Under ELF Based Severance Tax	3063.9	559.5	656.3	771.9	887.6	1003.3	1119.1	1235.0	1351.7	1467.7	1583.7	1699.6	1815.5	1931.5	2047.4	2163.4
Under HB63	4663.6	515.1	637.4	769.3	911.2	1032.8	1154.5	1276.2	1397.9	1519.6	1641.3	1763.0	1884.7	2006.4	2128.1	2249.8
Corporate Income Tax (ANS)																
Production	495.1	189.9	203.9	217.9	231.9	245.9	259.9	273.9	287.9	301.9	315.9	329.9	343.9	357.9	371.9	385.9
TAPS	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Total Petroleum	\$538.38	\$233.18	\$247.18	\$261.18	\$275.18	\$289.18	\$303.18	\$317.18	\$331.18	\$345.18	\$359.18	\$373.18	\$387.18	\$401.18	\$415.18	\$429.18
TAPS tax allowance (Millions \$)	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22	216.22
TAPS after tax margin	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39	267.39
TAPS deferred return	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88	46.88
Revenue Share with Under ELF Based Severance Tax																
Federal Revenue (Millions \$)	3046.5	-566.3	-394.3	-228.8	-63.3	102.1	267.5	432.8	598.0	763.3	928.7	1094.0	1259.4	1424.7	1590.1	1755.4
Percentage Total	24.8%	0.0%	0.0%	0.0%	0.0%	8.8%	12.3%	16.8%	17.7%	18.1%	20.2%	21.1%	22.9%	22.3%	22.7%	23.1%
Company Net Revenue (Millions \$)	5650.9	-1058.7	-739.2	-431.8	-124.8	182.7	489.8	796.7	1103.5	1410.8	1717.7	2024.8	2331.9	2639.0	2946.0	3253.1
Percentage Total	46.8%	0.0%	0.0%	0.0%	0.0%	11.8%	22.3%	28.8%	32.8%	36.4%	37.4%	38.0%	40.3%	41.3%	42.1%	42.8%
State Revenue + Muni Share Oil Property (Million \$)	3602.3	792.7	903.5	1033.0	1162.7	1292.4	1422.3	1552.5	1682.9	1812.9	1942.8	2072.8	2202.7	2332.7	2462.6	2592.6
Percentage Total	29.3%	0.0%	0.0%	0.0%	0.0%	81.9%	85.3%	88.8%	88.7%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%
Total Revenue Shared State, Federal, Company	12299.8	-832.3	-229.9	372.5	974.8	1577.2	2179.6	2782.0	3384.4	3986.8	4589.2	5191.6	5794.0	6396.3	6998.7	7601.1
Revenue Share Under HB63																
Federal Revenue (Millions \$)	2486.6	-550.8	-387.6	-227.9	-71.6	91.8	255.1	405.4	552.5	696.6	837.4	975.1	1109.6	1240.9	1369.0	1493.9
Percentage Total	20.2%	0.0%	0.0%	0.0%	0.0%	5.8%	11.7%	14.8%	15.3%	17.5%	18.2%	18.8%	19.2%	19.4%	19.8%	19.7%
Company Net Revenue (Millions \$)	4611.1	-1029.8	-726.9	-430.2	-140.0	163.5	466.8	746.0	1019.2	1286.7	1548.3	1803.9	2053.7	2297.5	2535.4	2767.4
Percentage Total	37.5%	0.0%	0.0%	0.0%	0.0%	10.4%	21.4%	28.8%	30.1%	32.3%	33.7%	34.7%	36.4%	36.2%	36.4%	36.4%
State Revenue + Muni Share Oil Property (Million \$)	5202.0	748.3	884.6	1030.5	1186.4	1322.0	1457.7	1603.6	1812.7	2003.6	2203.5	2412.6	2630.7	2858.0	3094.4	3339.9
Percentage Total	42.3%	0.0%	0.0%	0.0%	0.0%	83.8%	86.9%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%
Total Revenue Shared State, Federal, Company	12299.8	-832.3	-229.9	372.5	974.8	1577.2	2179.6	2782.0	3384.4	3986.8	4589.2	5191.6	5794.0	6396.3	6998.7	7601.1

[illegible]

ANS State Severance Tax Collections and Effective Tax Rate Under the Current ELF based system and the proposed HB63

ANS Market Price	\$3.60	\$10	\$12	\$14	\$16	\$18	\$20	\$22	\$24	\$26	\$28	\$30	\$32	\$34	\$36	\$38	\$40	\$42	\$44
ANS Oil Severance Tax Collections (millions of \$)																			
Status Quo	953.4	107.7	128.5	168.0	207.7	247.3	287.0	326.7	366.3	406.0	445.7	485.4	525.0	564.7	604.4	644.0	683.7	723.4	763.0
Under HB63	2,553.1	63.3	109.6	165.4	231.3	276.9	322.4	404.7	496.1	596.7	706.3	825.1	953.0	1,090.0	1,236.1	1,391.4	1,555.7	1,729.2	1,911.7
Difference	1,599.7	-44.4	-18.9	-2.6	23.7	29.5	35.4	78.0	129.8	190.7	260.7	339.8	428.0	525.3	631.8	747.4	872.0	1,005.8	1,148.7
Average Effective Tax Rate																			
Status Quo	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
Under HB63	21.1%	6.2%	7.1%	8.0%	9.0%	9.0%	9.0%	9.9%	10.8%	11.7%	12.6%	13.5%	14.4%	15.3%	16.2%	17.1%	18.0%	18.8%	19.7%

* FY2007 Price from Spring 2006 Forecast

ANS State Severance

ANS Market Price	\$46	\$48	\$50	\$52	\$54	\$56	\$58	\$60	\$62	\$64	\$66	\$68	\$70	\$72	\$74	\$76	\$78	\$80
ANS Oil Severance Tax Collection																		
Status Quo	802.7	842.4	882.0	921.7	961.4	1,001.0	1,040.7	1,080.4	1,120.1	1,159.7	1,199.4	1,239.1	1,278.7	1,318.4	1,358.1	1,397.7	1,437.4	1,477.1
Under HB63	2,057.8	2,178.9	2,301.0	2,424.9	2,550.4	2,677.7	2,806.8	2,937.6	3,070.1	3,204.3	3,340.3	3,478.1	3,617.6	3,758.8	3,901.7	4,046.4	4,192.9	4,341.0
Difference	1,255.1	1,336.6	1,419.0	1,503.2	1,589.1	1,676.7	1,766.1	1,857.2	1,950.0	2,044.6	2,140.9	2,239.0	2,338.8	2,440.4	2,543.7	2,648.7	2,755.4	2,863.9
Average Effective Tax Rate																		
Status Quo	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
Under HB63	20.2%	20.4%	20.6%	20.7%	20.9%	21.1%	21.2%	21.4%	21.6%	21.8%	21.9%	22.1%	22.3%	22.5%	22.6%	22.8%	23.0%	23.2%

¹ FY2007 Price from Spring 2006 f

Saturday, August 05, 2006

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www.2**House Republicans ready to end debate on oil tax**

Friday, August 4, 2006 - by Bill McAllister

Juneau, Alaska -

The House of Representatives is formally taking the lead on the oil tax. What once was a free-flowing debate has become more rigid and partisan in the past two days.



Jason Kohler/KTUU-TV

The oil tax debate this year had broken all the rules, with nothing decided in caucus, everybody a free agent and the outcome unknown. But finally House Republicans say they're determined to wrap it up. House Speaker John Harris says the Republican majority has decided to get behind the newest version of the oil production tax, which ties tax rates to oil company investments.



Jason Kohler/KTUU-TV

"I think there are votes in a bipartisan manner maybe for a different way to go about doing things, but we're trying to make this as much as possible a unified Republican approach, and hopefully it works," said (left), R-Valdez.

Democrats expect the new bill to pass House floor tomorrow. Despite Gov. Frank Murkowski's veto threat, they are pushing to abandon a profits-based production tax in favor of a tax on value.

"If we get a straight vote on the gross, it will pass overwhelmingly -- both the House and the Senate," said House Minority Leader Ethan Berkowitz (right), D-Anchorage.



Some House Democrats are so adamant about

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars:	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00
Effective Tax Rate (Percent)							
HCS for SB 2001 ²	4.2%	8.5%	12.7%	16.2%	20.1%	23.7%	27.1%
CC for SB 2001 (22.8/20, 0.175% at \$35 Net Trigger) ³	3.4%	8.0%	12.2%	15.3%	18.5%	21.3%	23.9%
SB 2001 ³	0.0%	7.3%	11.6%	14.5%	17.0%	19.0%	20.8%
Alaska Government Take (Percent)							
HCS for SB 2001 ²	39.8%	33.0%	33.6%	35.1%	37.6%	40.0%	42.4%
CC for SB 2001 (22.8/20, 0.175% at \$35 Net Trigger) ³	38.4%	32.5%	33.1%	34.2%	36.0%	37.7%	39.5%
SB 2001 ³	32.7%	31.6%	32.5%	33.3%	34.5%	35.6%	36.6%
Total Government Take (Percent)							
HCS for SB 2001 ²	67.2%	59.8%	59.4%	59.9%	61.3%	62.7%	64.2%
CC for SB 2001 (22.8/20, 0.175% at \$35 Net Trigger) ³	66.3%	59.5%	59.0%	59.4%	60.3%	61.3%	62.3%
SB 2001 ³	62.6%	58.9%	58.6%	58.8%	59.3%	59.9%	60.4%
Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)							
HCS for SB 2001 ²	(\$78)	\$148	\$588	\$1,156	\$1,956	\$2,898	\$3,981
CC for SB 2001 (22.8/20, 0.175% at \$35 Net Trigger) ³	(\$109)	\$122	\$544	\$1,056	\$1,730	\$2,504	\$3,376
SB 2001 ³	(\$240)	\$76	\$490	\$956	\$1,514	\$2,129	\$2,801

June 8, 2006
11:55 PM

¹ Assumes no major gas sale

² Calculated from April 2006. Includes transition (50% of capex over 1-7 years to maximum of \$5 Billion) and \$60 Million exemption over 5 companies for 10 years. Volumes per DOR Spring 2006 Forecast with OoGuruk projection

³ Calculated from April 2006. Includes transition (50% of capex over 1-7 years to maximum of \$5 Billion) and \$60 Million exemption over 8 companies for 10 years. Volumes per DOR Spring 2006 Forecast with OoGuruk projection



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Key Model Assumptions

▪ Production Rate of Gas (Excluding CO ₂)	~4.5 Bcf/d
▪ Delivery into Pipeline	4.3 Bcf/d
▪ Gas Delivered at Alberta	4.2 Bcf/d
▪ Pipeline, GTP Construction Costs (2005 \$M)	
-- to AECO (Most Likely Case)	\$13,600
-- to Chicago (Unlikely)	\$21,000
▪ Additional Upstream Investment Including PTU Capital, PT Feeder Line & YTF Gas Capital -- 80% Gas-Related (2005 \$M)	\$9,200
▪ Pipeline Commission Date	2015
▪ Full Capacity Date	2016

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars:	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00
Effective Tax Rate (Percent)							
Administration 20/20 ²	0.0%	7.1%	10.8%	12.0%	13.5%	14.5%	15.2%
Senate Resources CS ³	0.5%	9.9%	14.8%	18.8%	22.0%	24.8%	27.2%
House Resources CS ⁴	0.0%	7.2%	10.9%	14.9%	18.9%	22.5%	25.9%
Original House ⁵	0.0%	7.2%	11.3%	14.6%	18.5%	22.0%	25.3%
Original Senate ⁶	0.0%	7.0%	11.2%	14.5%	17.8%	20.7%	23.3%
Current Senate ⁷	0.0%	7.3%	11.6%	14.4%	16.9%	19.0%	20.8%
Alaska Government Take (Percent)							
Administration 20/20 ²	32.8%	31.3%	31.5%	30.8%	31.0%	31.1%	31.2%
Senate Resources CS ³	33.5%	34.7%	35.8%	37.7%	39.3%	40.9%	42.5%
House Resources CS ⁴	32.8%	31.5%	31.7%	33.7%	36.3%	38.8%	41.2%
Original House ⁵	32.8%	31.5%	32.0%	33.4%	35.9%	38.3%	40.7%
Original Senate ⁶	32.8%	31.2%	32.0%	33.3%	35.3%	37.1%	38.8%
Current Senate ⁷	32.8%	31.5%	32.4%	33.2%	34.4%	35.5%	36.5%
Total Government Take (Percent)							
Administration 20/20 ²	62.9%	58.9%	58.1%	57.3%	57.2%	57.1%	57.1%
Senate Resources CS ³	63.4%	61.1%	60.9%	61.7%	62.5%	63.4%	64.3%
House Resources CS ⁴	62.9%	59.0%	58.2%	59.1%	60.6%	62.0%	63.5%
Original House ⁵	62.9%	59.0%	58.5%	59.0%	60.3%	61.7%	63.2%
Original Senate ⁶	62.9%	58.8%	58.4%	58.9%	59.9%	60.9%	61.9%
Current Senate ⁷	62.9%	59.0%	58.7%	58.8%	59.4%	59.9%	60.5%
Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)							
Administration 20/20 ²	(\$256)	\$55	\$416	\$683	\$1,044	\$1,405	\$1,766
Senate Resources CS ³	(\$238)	\$240	\$787	\$1,489	\$2,280	\$3,160	\$4,126
House Resources CS ⁴	(\$256)	\$62	\$431	\$1,022	\$1,826	\$2,771	\$3,867
Original House ⁵	(\$256)	\$62	\$462	\$993	\$1,767	\$2,688	\$3,755
Original Senate ⁶	(\$256)	\$46	\$457	\$979	\$1,677	\$2,474	\$3,360
Current Senate ⁷	(\$256)	\$66	\$492	\$971	\$1,546	\$2,180	\$2,873

¹ Assumes no major gas sale

² Calculated from July 2005. Includes 5-year horizon (2007-2011) and 15-year horizon (2007-2021) for the 20/20 scenario. Assumes no major gas sale.

³ Calculated from April 2006. Includes 5-year horizon (2007-2011) and 15-year horizon (2007-2021) for the Senate Resources scenario. Assumes no major gas sale.

⁴ Calculated from April 2006. Includes 5-year horizon (2007-2011) and 15-year horizon (2007-2021) for the House Resources scenario. Assumes no major gas sale.

⁵ Calculated from April 2006. Includes 5-year horizon (2007-2011) and 15-year horizon (2007-2021) for the Original House scenario. Assumes no major gas sale.

⁶ Calculated from April 2006. Includes 5-year horizon (2007-2011) and 15-year horizon (2007-2021) for the Original Senate scenario. Assumes no major gas sale.

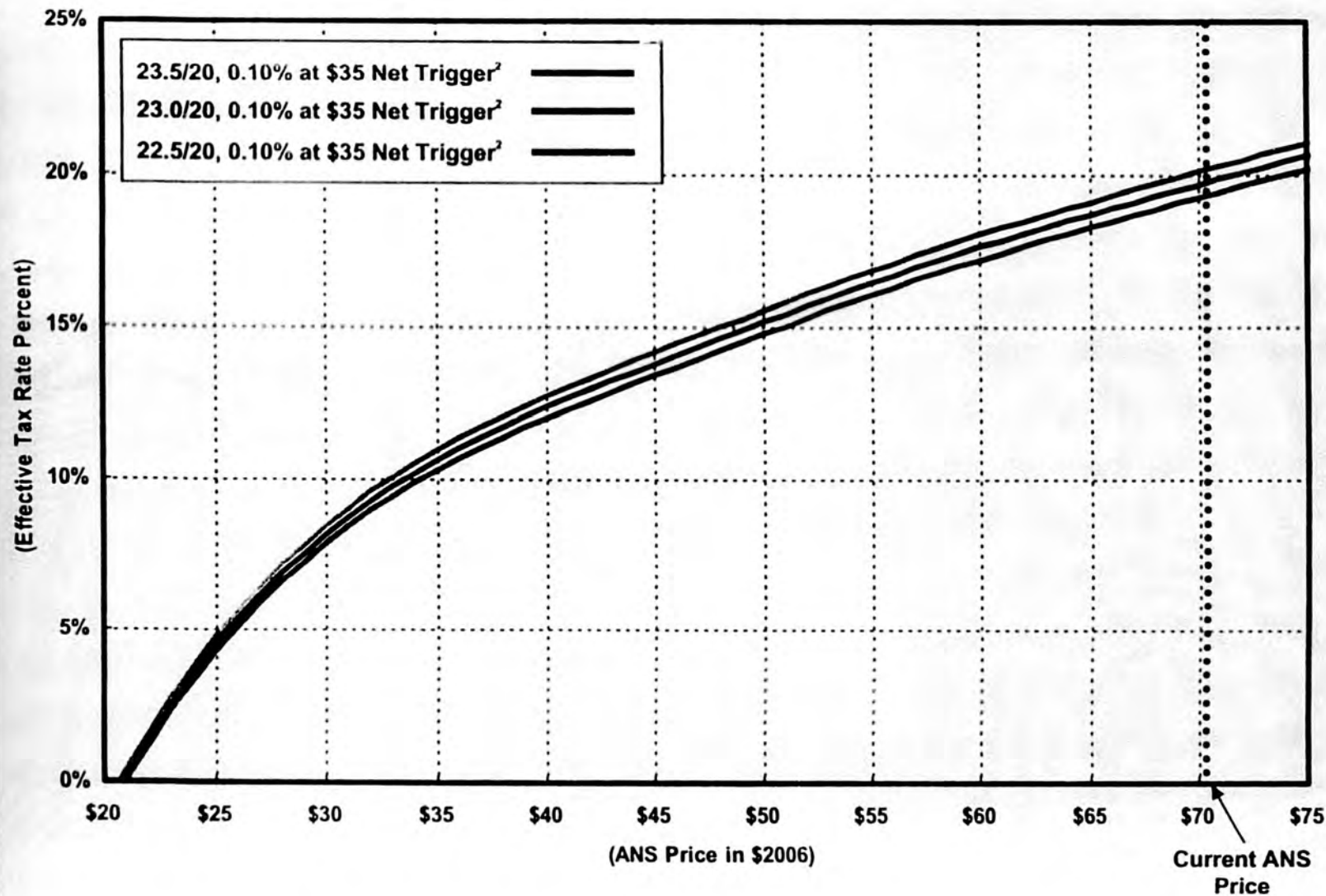
⁷ Calculated from April 2006. Includes 5-year horizon (2007-2011) and 15-year horizon (2007-2021) for the Current Senate scenario. Assumes no major gas sale.

Key Model Assumptions

▪ Production Rate of Gas (Excluding CO ₂)	~4.5 Bcf/d
▪ Delivery into Pipeline	4.3 Bcf/d
▪ Gas Delivered at Alberta	4.2 Bcf/d
▪ Pipeline, GTP Construction Costs (2005 \$M)	
-- to AECO (Most Likely Case)	\$13,600
-- to Chicago (Unlikely)	\$21,000
▪ Additional Upstream Investment Including PTU Capital, PT Feeder Line & YTF Gas Capital – 80% Gas-Related (2005 \$M)	\$9,200
▪ Pipeline Commission Date	2015
▪ Full Capacity Date	2016

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)



June 7, 2006
12:40 AM

¹ Assumes no major gas sale

² Calculated from April 2006, includes transition (50% of capex over 1-7 years to maximum of \$5 Billion) and \$60 Million exemption over 5 companies for 10 years, volumes per DOR Spring 2006 forecast with Oooguruk projection

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Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

Effective Tax Rate (Percent)

22.5/20, 0.10% at \$35 Net Trigger ²	0.0%	7.9%	12.0%	14.8%	17.2%	19.2%	21.0%
23.0/20, 0.10% at \$35 Net Trigger ²	0.0%	8.2%	12.4%	15.2%	17.6%	19.7%	21.5%
23.5/20, 0.10% at \$35 Net Trigger ²	0.0%	8.5%	12.7%	15.5%	18.0%	20.1%	21.9%

Alaska Government Take (Percent)

22.5/20, 0.10% at \$35 Net Trigger ²	32.7%	32.3%	32.9%	33.6%	34.7%	35.8%	36.8%
23.0/20, 0.10% at \$35 Net Trigger ²	32.7%	32.6%	33.3%	34.0%	35.1%	36.2%	37.2%
23.5/20, 0.10% at \$35 Net Trigger ²	32.7%	33.0%	33.6%	34.4%	35.5%	36.6%	37.6%

Total Government Take (Percent)

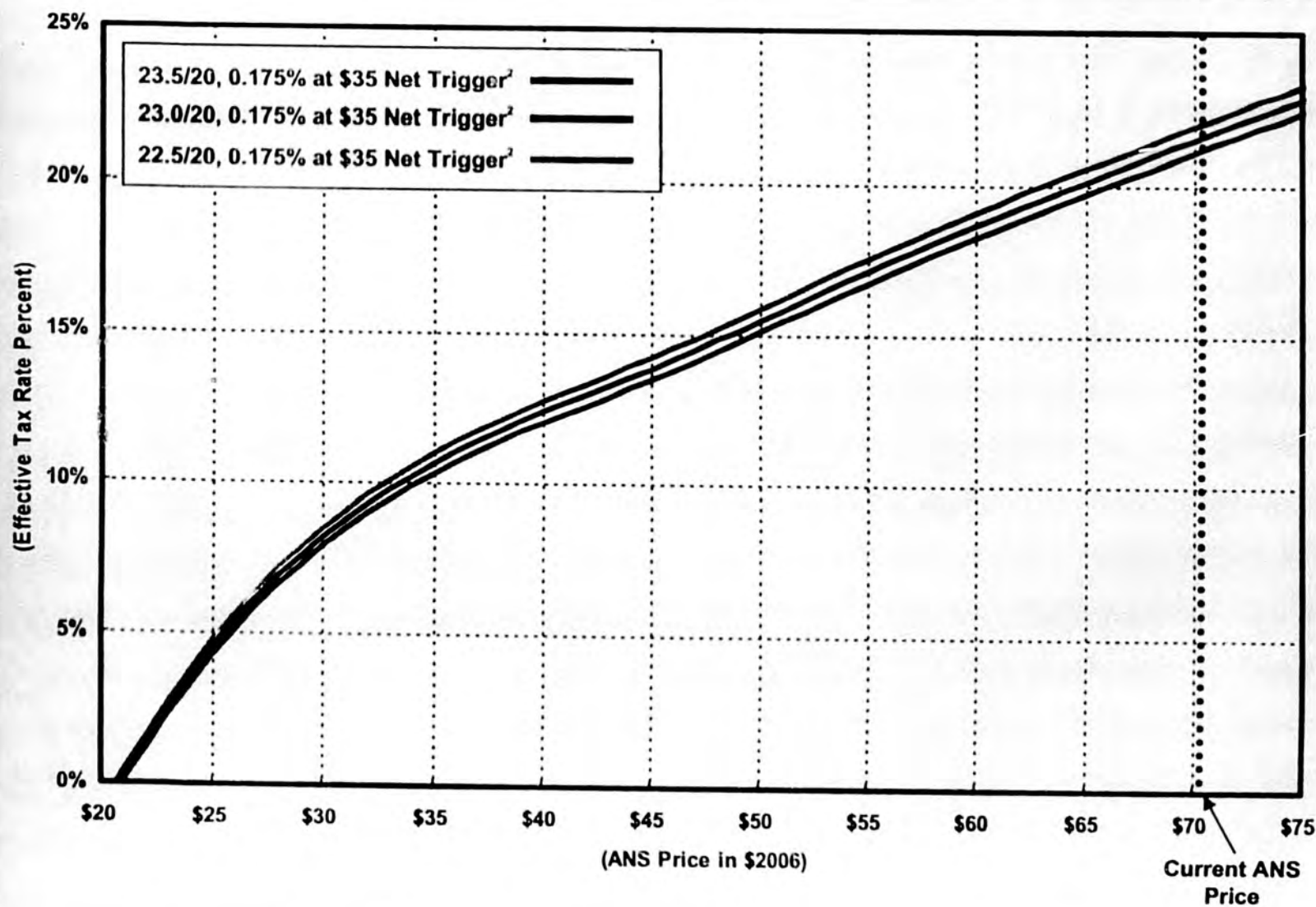
22.5/20, 0.10% at \$35 Net Trigger ²	62.6%	59.3%	58.9%	59.0%	59.5%	60.0%	60.5%
23.0/20, 0.10% at \$35 Net Trigger ²	62.6%	59.6%	59.1%	59.2%	59.7%	60.2%	60.8%
23.5/20, 0.10% at \$35 Net Trigger ²	62.6%	59.8%	59.4%	59.5%	60.0%	60.5%	61.1%

Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)

22.5/20, 0.10% at \$35 Net Trigger ²	(\$240)	\$111	\$525	\$991	\$1,549	\$2,165	\$2,836
23.0/20, 0.10% at \$35 Net Trigger ²	(\$240)	\$130	\$556	\$1,035	\$1,606	\$2,234	\$2,918
23.5/20, 0.10% at \$35 Net Trigger ²	(\$240)	\$148	\$588	\$1,079	\$1,662	\$2,303	\$3,000

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)



June 7, 2006
12:40 AM

¹ Assumes no major gas sale

² Calculated from April 2006 includes transition (50% of capex over 1-7 years to maximum of \$5 Billion) and \$60 Million exemption over 5 companies for 10 years. Volumes per DOR Spring 2006 Forecast with Odegasur projection.



Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

Effective Tax Rate (Percent)

22.5/20, 0.175% at \$35 Net Trigger ²	0.0%	7.9%	12.0%	15.1%	18.3%	21.1%	23.6%
23.0/20, 0.175% at \$35 Net Trigger ²	0.0%	8.2%	12.4%	15.5%	18.7%	21.5%	24.1%
23.5/20, 0.175% at \$35 Net Trigger ²	0.0%	8.5%	12.7%	15.9%	19.1%	21.9%	24.5%

Alaska Government Take (Percent)

22.5/20, 0.175% at \$35 Net Trigger ²	32.7%	32.3%	32.9%	34.0%	35.8%	37.5%	39.2%
23.0/20, 0.175% at \$35 Net Trigger ²	32.7%	32.6%	33.3%	34.4%	36.2%	37.9%	39.6%
23.5/20, 0.175% at \$35 Net Trigger ²	32.7%	33.0%	33.6%	34.8%	36.6%	38.3%	40.0%

Total Government Take (Percent)

22.5/20, 0.175% at \$35 Net Trigger ²	62.6%	59.3%	58.9%	59.2%	60.1%	61.1%	62.1%
23.0/20, 0.175% at \$35 Net Trigger ²	62.6%	59.6%	59.1%	59.5%	60.4%	61.4%	62.4%
23.5/20, 0.175% at \$35 Net Trigger ²	62.6%	59.8%	59.4%	59.7%	60.6%	61.6%	62.6%

Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)

22.5/20, 0.175% at \$35 Net Trigger ²	(\$240)	\$111	\$525	\$1,029	\$1,696	\$2,462	\$3,327
23.0/20, 0.175% at \$35 Net Trigger ²	(\$240)	\$130	\$556	\$1,073	\$1,753	\$2,531	\$3,409
23.5/20, 0.175% at \$35 Net Trigger ²	(\$240)	\$148	\$588	\$1,117	\$1,809	\$2,600	\$3,490

June 7, 2006
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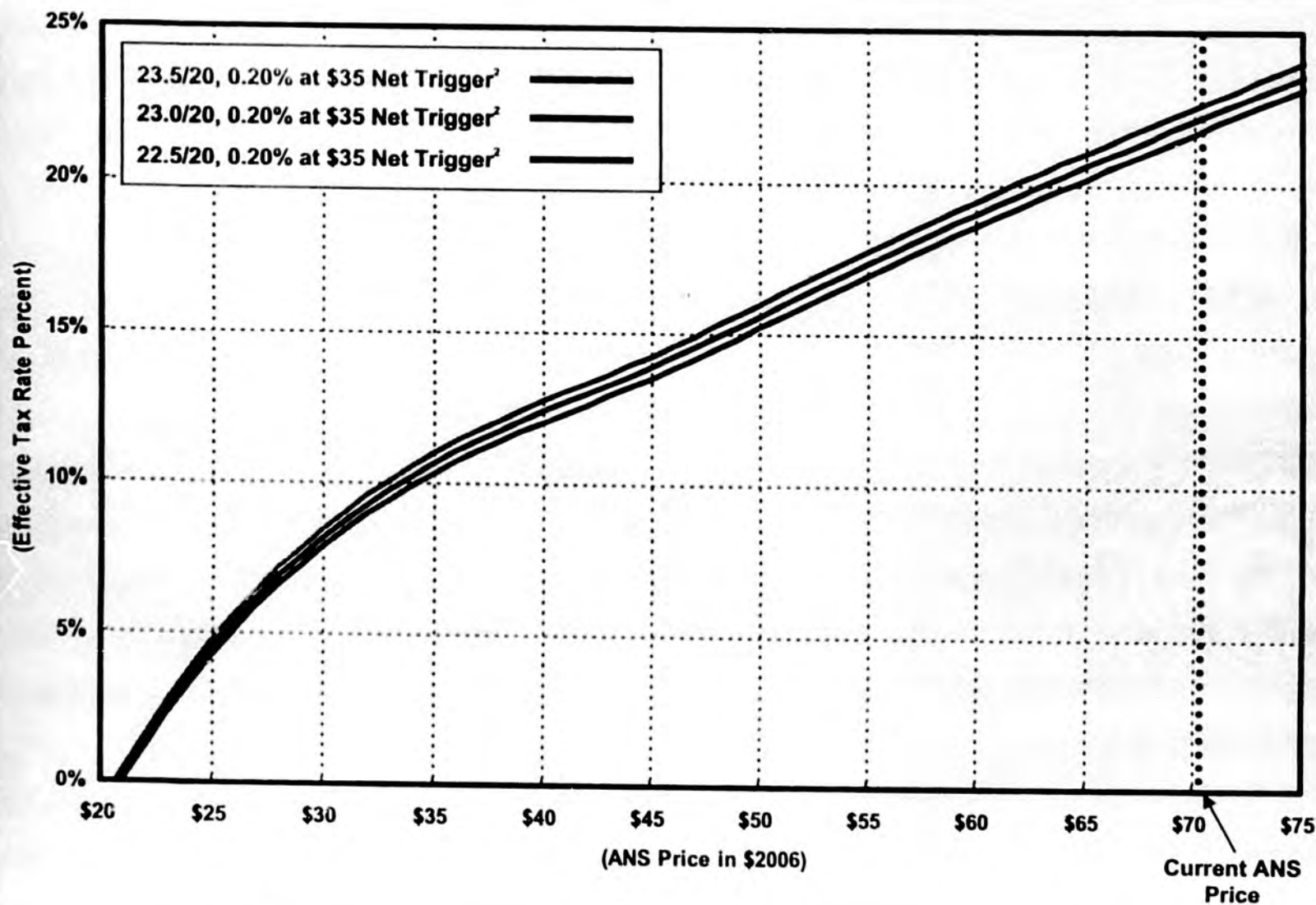
² Assumes no major gas sale

¹ Calculated from April 2006. Includes transition (50% of capex over 1-7 years to maximum of \$5 billion) and \$60 million exemption over 5 companies for 10 years. Volumes per DOR Spring 2006 Forecast with Ooqogruk projection.

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Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)



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Assumes no major gas sale

¹ Calculated from April 2006, includes transition (50% of capex over 1-7 years to maximum of \$5 Billion) and \$10 Million exemption over 5 companies for 10 years, volumes per DGM Spring 2006 Forecast with Odebrecht projection



Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars: \$20.00 \$30.00 \$40.00 \$50.00 \$60.00 \$70.00 \$80.00

Effective Tax Rate (Percent)

22.5/20, 0.20% at \$35 Net Trigger ²	0.0%	7.9%	12.0%	15.2%	18.6%	21.7%	24.5%
23.0/20, 0.20% at \$35 Net Trigger ²	0.0%	8.2%	12.4%	15.6%	19.0%	22.1%	24.9%
23.5/20, 0.20% at \$35 Net Trigger ²	0.0%	8.5%	12.7%	16.0%	19.4%	22.5%	25.4%

Alaska Government Take (Percent)

22.5/20, 0.20% at \$35 Net Trigger ²	32.7%	32.3%	32.9%	34.1%	36.1%	38.1%	40.0%
23.0/20, 0.20% at \$35 Net Trigger ²	32.7%	32.6%	33.3%	34.5%	36.5%	38.5%	40.4%
23.5/20, 0.20% at \$35 Net Trigger ²	32.7%	33.0%	33.6%	34.9%	36.9%	38.9%	40.8%

Total Government Take (Percent)

22.5/20, 0.20% at \$35 Net Trigger ²	62.6%	59.3%	58.9%	59.3%	60.4%	61.5%	62.6%
23.0/20, 0.20% at \$35 Net Trigger ²	62.6%	59.6%	59.1%	59.5%	60.6%	61.7%	62.9%
23.5/20, 0.20% at \$35 Net Trigger ²	62.6%	59.8%	59.4%	59.8%	60.9%	62.0%	63.1%

Annual Average Tax Difference Above/(Below) Status Quo (\$2006 M)

22.5/20, 0.20% at \$35 Net Trigger ²	(\$240)	\$111	\$525	\$1,042	\$1,745	\$2,562	\$3,491
23.0/20, 0.20% at \$35 Net Trigger ²	(\$240)	\$130	\$556	\$1,086	\$1,802	\$2,631	\$3,572
23.5/20, 0.20% at \$35 Net Trigger ²	(\$240)	\$148	\$588	\$1,130	\$1,858	\$2,700	\$3,654

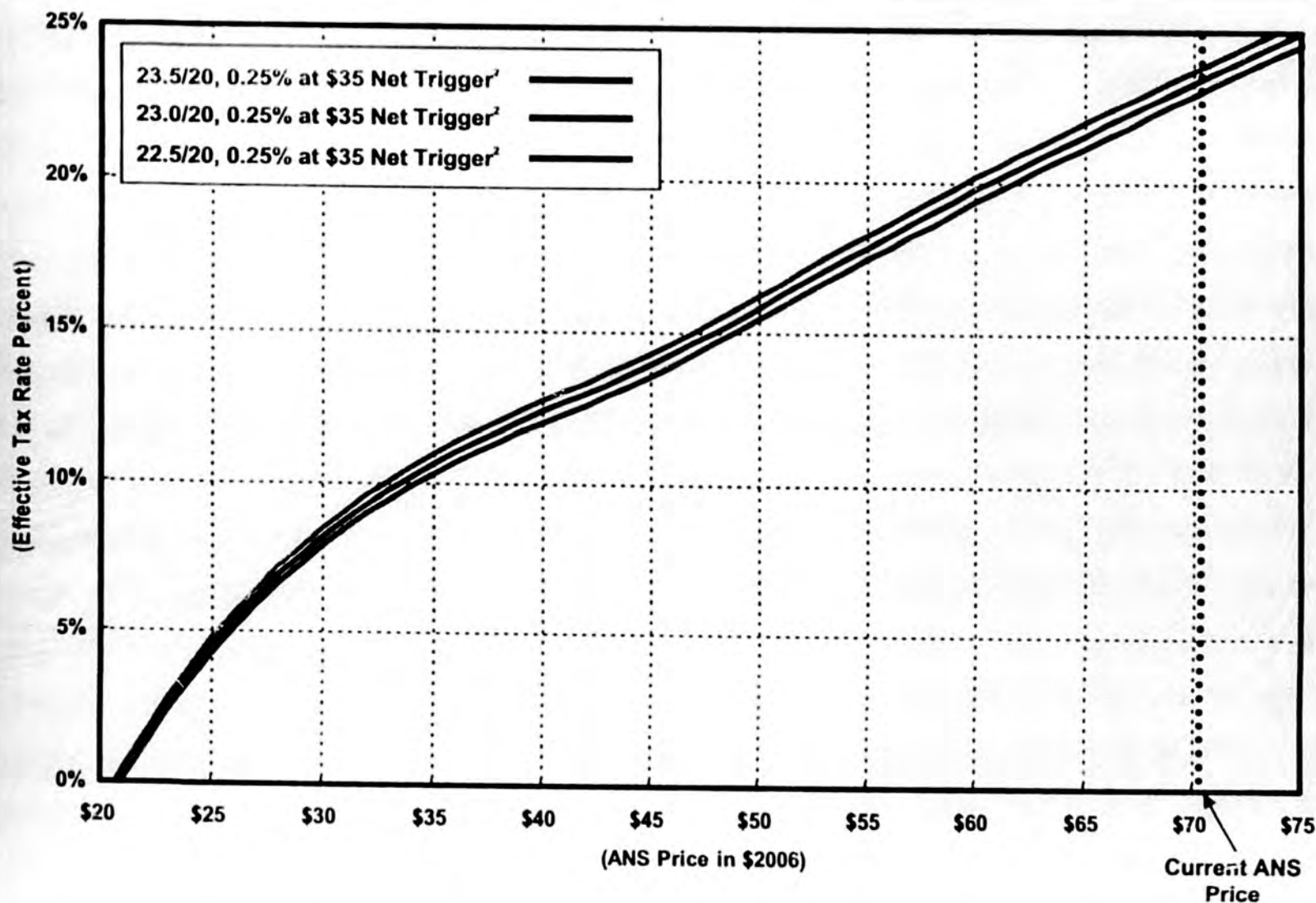
² Assumes no major gas sale

¹ Calculated from April 2006 includes transition (50% of capex over 1-7 years to maximum of \$5 billion and \$60 Million capex over 5 companies for 10 years) volumes per DOR Spring 2006 Forecast with Odebrecht projection

econ
ONE

Effective Average Tax Rates at Various Price Levels¹

(FY 2007-2016)



June 7, 2006
12:40 AM

¹ Assumes no major gas sale

² Calculated from April 2006 includes transition (50% of capex over 1-7 years to maximum of \$5 Billion) and \$60 Million exemption over 5 companies for 10 years, volumes per DOR Spring 2006 Forecast with Odebrecht projection

According to BP....

- “It is very likely that, in the medium term, prices will stand at about **\$40 on average**.

-Lord John Browne, CEO of BP
(Guardian Unlimited, 7/12/2006)*

* <http://business.guardian.co.uk/print/0,,329502870-108725,00.html>, “BP’s Browne predicts oil price fall” 6



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BP Boosts Dollar Dividend By 26 Per Cent

Release date: 08 February 2005

Download the full version of the results using the link on the right.

View or download the presentation hosted by John Browne (Group Chief Executive), Byron Grote (Chief Financial Officer) and Fergus MacLeod (Head of Investor Relations).

► View or download an archive of the webcast

BP today announced a 26 per cent boost to its fourth quarter dollar dividend compared with last year, the biggest single increase in its recent history.

Citing the "strong prevailing circumstances of the Group, along with future investment patterns and the forward trading environment", chief executive Lord Browne said BP had decided to make a significant one-time step-change in the dividend from 7.1 to 8.5 cents a share.

"Thereafter, we would expect to grow the dividend in line with our view of future sustainable performance. We estimate that this level of dividend allows us to maintain prudent earnings cover even if oil prices went down to \$20 dollars a barrel," he said.

Previewing an update on Group strategy to financial analysts scheduled for later today, Browne said: "We are aware that many of our investors are sterling-based and that the dollar's weakness has had an impact on their sterling cash flows. This change will be to their benefit, with a sterling increase of 23 per cent in the fourth quarter dividend compared with last year.

"For the year as a whole, dollar-based investors will see an increase of 13 per cent and sterling-based investors a rise of 4 per cent."

Browne said the company had bought back more than \$7.5 billion of shares during 2004 and remained committed to returning "100 per cent of excess free cash flow to investors so long as oil prices remain above \$20 a barrel, all other things being appropriate.

"Looking at the potential cash that could be distributed over 2005 and 2006 through share buybacks and dividends, assuming an oil price of \$30 a barrel and depending on refining margins and other factors, the total amount available for distribution could be around \$23 billion.

"We could use some of the excess free cash flow, for example, for material acquisition if we saw opportunities which fitted our strategy. But we see no such opportunities at present."

Commenting on BP's record replacement cost profit of \$16.2 billion for 2004, up 26 per cent from the previous year, Browne said the company was in a strong financial condition. Post-tax cash flow for the year totalled \$24 billion, a rise of 42 per cent from 2003, and gearing stood at 24 per cent.

"Our strategy is on track and unchanged, our operations are in line with our previous indications, and we have a strong base of material assets and markets for a sustainable future."

In Exploration and Production, he said that on a UK GAAP basis the company had more than replaced annual output for the 12th year running – by 106 per cent for the Group and 110 per cent, including equity-accounted entities such as in Abu Dhabi and TIK-BP.

Major discoveries were made in Egypt, Sakhalin, the deepwater Gulf of Mexico, Trinidad and Angola, having made a net 1 billion barrels of oil equivalent to BP's resource base over the year.

Production in existing profit centres, mainly Alaska and the North Sea, showed a net decline of between 4.5 and 5 per cent, a trend expected to continue at an annual average rate of 3 per cent out to 2008. This was partly offset by a rise in output from new profit centres to over 1 million barrels a day of oil equivalent – a figure likely to increase substantially in 2005.

Capital expenditure in existing profit centres rose from \$9.2 billion in 2003 to \$9.5 billion last year and is expected to rise to some \$11.5 billion this year as a result of specific oil field inflation and a weaker dollar. Capex in new profit centres was \$6.1 billion in 2004 and, with new project spending now over its peak, is expected to fall to some \$5 billion this year.

TNK-BP's 2004 oil production rose nearly 14 per cent to 1.45 million barrels a day, or 1.66 million barrels including the 50 per cent of Slavneft added at the start of the year. Output is estimated to grow by some 5 per cent this year. Capex, which is self-funded, was \$1.5 billion in 2004, up from around \$1 billion in 2003, and is expected to reach approximately \$1.8 billion this year as new prospects are developed, including new extensions to Samotlor and the Ural project, both 4 billion barrel development options in West Siberia.

"Since the formation of TNK-BP, the total investment we've made has been \$5.3 billion and the total dividends received have been \$2.2 billion," Browne said.

Group production as a whole grew by 11 per cent in 2004. Output for 2005 would likely hit 4.1 million to 4.2 million barrels a day of oil equivalent before divestments, keeping BP on track to average annual production growth in excess of 5 per cent for the period 2004-2008. The exact level would depend on oil prices, the extent of divestments and various other factors. Capex for Exploration and Production would likely be between \$9.5 billion and \$10 billion in 2005 and 2006, depending on foreign exchange impacts and inflation.

Capex in refining would be level in 2005 at around \$1.3 billion. "The majority of our refining capacity is in the US where margins are structurally advantaged and our refineries are in the top quartile on net cash margins and return on investment. In Europe, after the divestment of Lavera and Grangemouth, our position should improve considerably. In retail, where store sales continue to grow, along with sales of BP's Ultimate premium fuel, capital spending would also remain stable at around \$950 million this year," Browne said.

"Our global gas sales rose to 32 billion cubic feet a day in 2004. In North America, where BP is the leading marketer, our gas sales were up 16 per cent over 2003. Going forward, we expect medium-term global growth of 2 to 3 per cent a year, in line with world gas demand, and we will concentrate increasingly on customers who best fit our capabilities."

In petrochemicals the company was on track with plans to divest the bulk of its olefins and derivatives business in phases commencing in the second half of this year, probably by way of an IPO, subject to market conditions and necessary approvals. BP spent \$200 million in its high-growth aromatics and acetyls business which generated competitive cash returns in 2004 - a figure likely to rise slightly this year as the company invests to keep its leadership position in the segment.

Browne said he expected capital spending for BP as a whole to total some \$14 billion in 2005. "The exact level will depend on the level of the dollar and our continuing track record of offsetting normal underlying annual inflation of some 2 per cent. For the medium term an investment level of around \$14 billion is a reasonable expectation."

"Divestments, with the exception of olefins and derivatives, are not presently expected to be large this year. We expect proceeds of around \$1.3 billion, composed of the balance due from the sale of Ormen Lange and normal portfolio optimisation."

Commenting on the oil price, he said that while he expected that demand for oil in 2005 would moderate compared to last year, "we've concluded that on the basis of the supply-demand balance and OPEC's five-year track record of maintaining production discipline, oil prices are likely to have a support level of around \$30 a barrel for at least the medium term."

"As far as BP is concerned, we will continue to use a Brent oil price of \$20 a barrel for the purpose of testing projects and planning our activity level in exploration and production. This allows us to maintain a portfolio of activities with strong returns."

Browne said that, while BP had been helped by the environment, "our success so far is due to our combination of strategy and discipline. Over the past few years we have built a strong base for the Group with material assets and markets into which we are investing. We're achieving the targets for growth we set ourselves, we're improving quality and we're maintaining financial strength."

"Importantly, in spite of the significantly better than expected trading environment, we are maintaining a disciplined approach to the execution of our strategy and consequently making sure that excess free cash flows are appropriately distributed to shareholders."

Gas Field Costs

Key Model Assumptions

• Production Rate of Gas (Excluding CO ₂)	~4.5 Bcf/d
• Delivery into Pipeline	4.3 Bcf/d
• Gas Delivered at Alberta	4.2 Bcf/d
• Pipeline, GTP Construction Costs (2005 \$M)	
-- to AECO (Most Likely Case)	\$13,600
-- to Chicago (Unlikely)	\$21,000
• Additional Upstream Investment Including PTU Capital, PT Feeder Line & YTF Gas Capital -- 80% Gas-Related (2005 \$M)	\$9,200
• Pipeline Commission Date	2015
• Full Capacity Date	2016

CCON
ONT

PPT Gas Credits & Deductions Largely Erase PPT Revenue Benefits

10 years of Additional PPT Revenue at \$40/barrel:

Governor's PPT¹: \$4.9 Billion over status quo

House PPT²: \$5.88 Billion over status quo

^{New}
Senate PPT³ : ~~\$4.92~~ Billion over status quo
5.46

40% of \$9.2 billion in gas field costs = **\$3.7 Billion**

¹ SB 2001

² HCS CSSB 2001

³ CSSB 2001

1.30pm

BP's Browne predicts oil price fall

Terry Macalister
Monday June 12, 2006

Guardian Unlimited

Lord Browne, BP's chief executive, held out the prospect of a big drop in crude oil prices to \$40 a barrel as he dismissed alarmist views that petroleum was running out very fast.

His optimism came despite a 1% rise in the price of Brent crude for July delivery to \$70.49 a barrel in morning trading in London as traders continued to fret about tensions in the Middle East.

It was barely a month ago that some industry experts were talking about the possibility of price spikes of \$100 a barrel and BP had condemned financial speculators for artificially pushing up prices.

But yesterday Lord Browne was eager to outline his belief that the value of oil on world markets should begin to return to more normal levels. "It is very likely that, in the medium term, prices will stand at about \$40 on average. In the very long run, even \$25 to \$30 are possible," he said in an interview with the German weekly news magazine Der Spiegel.

He accepted that there was little likelihood of prices dropping back sharply in the short term but dismissed notions that the price could only go up as scarcity increased. Large new oilfields were still being found, he said, adding that regions such as west Africa had plenty of hydrocarbons still in place that could be tapped.

He also noted that Canada's oil sands could also be exploited profitably. Even though they were expensive to bring out of the ground, production costs remained well below world selling prices for crude.

BP has so far kept away from these "unconventional" oil projects but Shell has been investing enthusiastically in the tar schemes of Alberta, Canada, buying up companies engaged in such output.

Lord Browne warned at BP's annual results presentation on April 25 that fear was one of the factors driving up crude prices that helped his company produce underlying profits of £3bn in the first quarter of the year.

Yesterday the July price of Brent rose on the Intercontinental Exchange (ICE) futures market but light sweet crude for the same month's delivery was down 11 cents to \$71.52 a barrel in Asian electronic trading on the New York Mercantile Exchange.

Singapore traders were said to be only slightly relieved by the first comments from the Iranian government about the incentive package put forward by Europe and the US to try to break the deadlock over the nuclear programme.

Victor Shum, an energy analyst in Singapore with the US consultancy Purvin & Gertz, said: "The market's aware that the Iranian issue is not going to be resolved in the short-term."

Guardian Unlimited © Guardian Newspapers Limited 2006

“[Legislators] should during this session adopt a gross production tax for oil, separate from gas taxes.”

-Jack Coghill & Vic Fischer

Anchorage Daily News - July 19, 2006

“Currently the companies pay taxes based on the price of a barrel of oil produced from Alaska oil fields. It’s an uncomplicated and transparent system. We know the price of oil and we know how much oil moves through our pipeline.

-Larry Carr

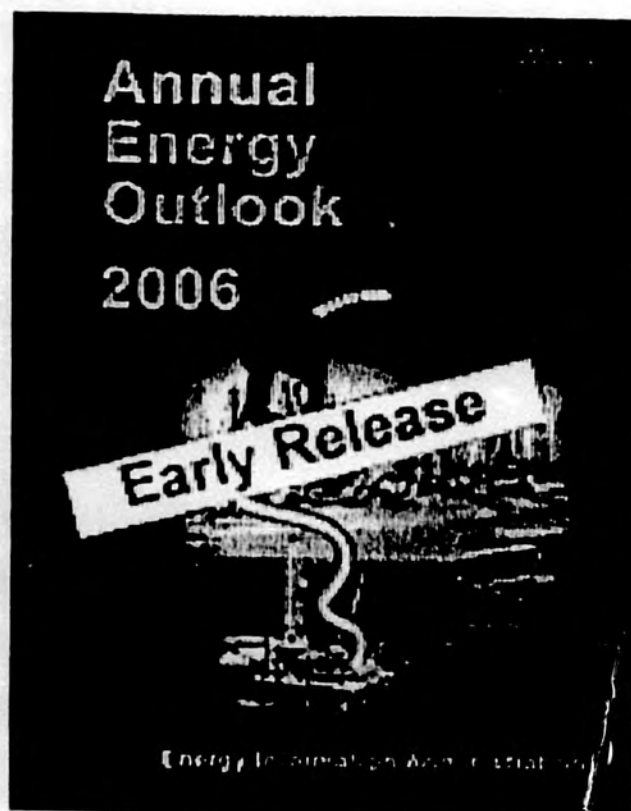
Anchorage Daily News - July 8, 2006

Taxing on the Gross is Straightforward

- Current law taxes a percentage of the sales value of oil
- The sales value is easier to verify than company profits

PPT Bets Alaska's Future On High Prices

According to the U.S. Energy Information Administration:



The long term annual average world oil price is forecasted to be **\$47** per barrel through 2025.

According to BP....

- “It is very likely that, in the medium term, prices will stand at about **\$40 on average**.

-Lord John Browne, CEO of BP

(Guardian Unlimited, 7/12/2006)*

* <http://business.guardian.co.uk/print/0,,329502870-108725,00.html>, “BP’s Browne predicts oil price fall”

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• Additional Upstream Investment Including PTU Capital, PT Feeder Line & YTF Gas Capital -- 80% Gas-Related (2005 \$M)	\$9,200
• Pipeline Commission Date	2015
• Full Capacity Date	2016

OCOR
ONE

What is Additional PPT Revenue at \$40/bbl?

According to Econ One:

Governor's PPT ¹ :	\$490 Million over status quo
House PPT ² :	\$588 Million over status quo
Senate PPT ³ :	\$492 Million over status quo

¹ SB 2001

² HCS CSSB 2001

³ CSSB 2001

PPT Gas Credits & Deductions Largely Erase PPT Revenue Benefits

10 years of Additional PPT Revenue at \$40/barrel:

Governor's PPT¹: \$4.9 Billion over status quo

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40% of \$9.2 billion in gas field costs = **\$3.7 Billion**

¹ SB 2001

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Gas Field Credits & Deductions Should be Taken from Gas Taxes, not Oil Taxes

“[Legislators] should during this session adopt a gross production tax for oil, *separate from gas taxes*.”

-Jack Coghill & Vic Fischer

Anchorage Daily News 7/19/06

WOOD MACKENZIE

GLOBAL OIL AND GAS — RISKS AND REWARDS 2004

Alaska's Profitability – Full Cycle, Post Government Take

Rate of Return (IRR – Nominal)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	15/49	14/52	14/53
Alaska's IRR	18.09%	23.57%	29.11%
Global Average IRR	15.20%	18.94%	23.07%

Full Cycle Government Take

Full Cycle Gov't Take (% Of Pre-Take Net Cash Flow, Undiscounted)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	33/54	24/54	19/55
Take on AK Production	71.70%	63.63%	58.40%
Global Ave. Take	70.86%	70.26%	73.34%



BP to buy back shares with free cash flow when oil price exceeds
\$26 a barrel

Release date: 29 March 2004

“... all the free cash generated when the oil price is
above that level would be returned to shareholders
through buybacks.”

Source: BP Press Release 3/29/04

Policy Restated in 2/08/05 BP Press Release

Profits At Lower Prices?

- AOGA states \$12.82/bbl is a “**high end estimate**” of what producers need to “**find, produce and transport**” ANS oil.

Source: Juneau Empire, 12/13/04

BP & ConocoPhillips

Alaska Profits

Year	2002	2003	2004	2005
Average Price of Oil	\$24.72	\$29.64	\$38.84	\$53.48
Alaska Profits				
<i>ConocoPhillips</i>	\$870 Million	\$1.4 Billion	\$1.8 Billion	\$2.55 Billion
<i>BP</i>	\$550 Million	\$872 Million	\$1.8 Billion	\$2.6 Billion
Company Profit Margin				
<i>ConocoPhillips</i>	29.0%	40.5%	41.8%	43.1%
<i>BP</i>	23.3%	27.5%	48.0%	53.0%

FY 2005 Oil Company Profit Margins

Gross Revenue from North
Slope Operation: \$13 billion

Estimated Corporate Profits: \$5.2 billion

Corporate Profit Margin: 40.3%

Source: AK Dept of Revenue

A Major Development Incentive – Facilities Access

- Former Division of Oil & Gas Director Mark Myers concluded that facilities access is one of the most important things Alaska can do to encourage new development
- SSHB 3004 Requires that if there is excess capacity at a facility, the facility owner shall make it available to independent producers at a “reasonable rate” – a standard currently used by the RCA in the telecommunications area
(AS 42.05.381)

Giving Companies More Profit Doesn't Guarantee More Investment

- "...as the world grapples with high prices, tight refining capacity and fears of shortages throughout the business, executives are finding that that's **more money than they can spend.**" Source: N.Y. Times, "Oil Companies in Quandary Over Cash Glut," 2/12/05
- "BP, which earned **\$16.2 billion** in 2004, will return as much as **\$23 billion** to its investors this year and next, mostly as dividends." Source: N.Y. Times 2/12/05

Providing Extra Revenue to Oil Companies Does Not Equal Additional Investment

	FY 2002	FY 2003	FY 2004	FY 2005	06
<i>Price of Oil</i>	\$21.78	\$28.15	\$31.74	\$43.44	
<i>Company Revenue</i>	\$1.7 Billion	\$2.9 Billion	\$3.5 Billion	\$5.2 Billion	\$7-

- Company investment in Alaska has stayed at roughly \$1 Billion

SCOMM

148:5

ALASKA STATE LEGISLATURE

REPRESENTATIVE KURT OLSON

- Chair, Labor and Commerce
- Vice-Chair, Oil and Gas
- Member, Community and Regional Affairs

Session: January – May
State Capitol
Juneau, AK 99801-1182
Phone: 907-465-2693
Fax: 907-465-3835



Interim: May – December
145 Main Street Loop, Ste 221
Kenai, AK 99611
Phone: 907-283-2690
Fax: 907-283-2763

Official Business

Sponsor Statement

HB 128 – Disallows PPT Reductions for Improperly Maintained Facilities

HB 128 cleans up language and closes a loophole in the recently passed Petroleum Production Tax (PPT) legislation.

As currently written, producers may deduct or use as credits, expenses for repairs made to infrastructure that has been improperly maintained. Once HB128 is enacted, deductions or credits against the PPT for these types of repairs will be subject to review and approval.

This bill instructs the Commissioner of the Revenue to consult with the Commissioner of the DEC and the Chair of AOGCC. Relying on standard practices of the industry, they will determine the portion of the costs related to repair or replacement of improperly maintained property or equipment available for deduction or use as a credit.

This concept came forward as an amendment in the Senate Resources Committee in early August of 2006. The ongoing corrosion problem currently experienced by BP serves to emphasize the importance of this change in statute.

The responsibility for the expenses related to repairs made to improperly maintained infrastructure should not lie with the State of Alaska.

I respectfully ask for your support of this bill.

ALASKA STATE LEGISLATURE

REPRESENTATIVE KURT OLSON

- Chair, Labor and Commerce
- Vice-Chair, Oil and Gas
- Member, Community and Regional Affairs

Session: January – May
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Official Business

Sectional Analysis

HB 128 - Disallows PPT Reductions for Improperly Maintained Facilities

Section 1: amends AS 43.55.165(e) which establishes lease expenditures not available for use as credits or deductions to the Petroleum Production Tax (PPT).

New subsection (19) establishes new language regarding costs related to the repair and replacement of improperly maintained property or equipment.

These costs are subject to review by the Commissioner of The Department of Revenue, the Commissioner of the Department of Environmental Conservation and the chair of the Alaska Oil and Gas Conservation Commission, relying on industry standards.

Section 2: provides for applicability to the oil and gas produced after March 31, 2006, as with the PPT.

Section 3: provides for transitional language for payment of additional taxes or installment payment due as a result of disallowing any expenditure set out in Section 1.

Section 4: provides for retroactive date to the same period as the PPT.

DRAFT CS HB 128

Comparisons between original bill and draft CS
25-LS0561\E vs work draft 25-LS0561\M

Page 3:

Line 21:

- Add "commissioner of natural resources"
- Delete "the chair of"
The intent is to include DNR as part of the consulting group and also have all members of AOGCC, not just the chair.

Line 22:

- Delete "relying on" and add "taking into consideration"
Makes language more general in nature.

Subsection (A), beginning on Line 24:

- Delete "improperly maintained property or equipment" and replace with "property or equipment that was not maintained or was improperly maintained".
Clarifies subsection (a) to insure "not maintained" is also established as criteria.

Subsection (B), beginning on Line 27:

- Add "a lack of"
Clarifies subsection (b), that improper or no maintenance are included.

Subsection (C), beginning on Line 29:

- Delete subsection and replace with:
"Incremental operating expenses incurred as a result of operating facilities or equipment at diminished capacity when that diminished capacity is caused by the lack of or improper maintenance of property or equipment"

To clarify incremental expenses for diminished capacity as a result of lack of or improper maintenance of facilities.

25-LS0561\JM
Bullock
2/22/07

CS FOR HOUSE BILL NO. 128()

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FIFTH LEGISLATURE - FIRST SESSION

BY

Offered:

Referred:

Sponsor(s): REPRESENTATIVES OLSON, Harris, Ramras, Guttenberg, Neuman, Holmes, Thomas, Stoltze, Joule, Fairclough, LeDoux, Kerttula, Wilson, Lynn, Crawford, Gara, Gruenberg, Doll, Doogan, Edgmon, Buch

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to allowable lease expenditures for the purpose of determining the
2 production tax value of oil and gas for the purposes of the oil and gas production tax;
3 and providing for an effective date."

4 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

5 * **Section 1.** AS 43.55.165(e) is amended to read:

6 (e) For purposes of this section, lease expenditures do not include

7 (1) depreciation, depletion, or amortization;

8 (2) oil or gas royalty payments, production payments, lease profit
9 shares, or other payments or distributions of a share of oil or gas production, profit, or
10 revenue;

11 (3) taxes based on or measured by net income;

12 (4) interest or other financing charges or costs of raising equity or debt
13 capital;

14 (5) acquisition costs for a lease or property or exploration license;

- 1 (6) costs arising from fraud, wilful misconduct, or gross negligence;
2 (7) fines or penalties imposed by law;
3 (8) costs of arbitration, litigation, or other dispute resolution activities
4 that involve the state or concern the rights or obligations among owners of interests in,
5 or rights to production from, one or more leases or properties or a unit;
6 (9) costs incurred in organizing a partnership, joint venture, or other
7 business entity or arrangement;
8 (10) amounts paid to indemnify the state; the exclusion provided by
9 this paragraph does not apply to the costs of obtaining insurance or a surety bond from
10 a third-party insurer or surety;
11 (11) surcharges levied under AS 43.55.201 or 43.55.300;
12 (12) for a transaction that is an internal transfer or is otherwise not an
13 arm's length transaction, expenditures incurred that are in excess of fair market value;
14 (13) an expenditure incurred to purchase an interest in any corporation,
15 partnership, limited liability company, business trust, or any other business entity,
16 whether or not the transaction is treated as an asset sale for federal income tax
17 purposes;
18 (14) a tax levied under AS 43.55.011;
19 (15) the portion of costs incurred for dismantlement, removal,
20 surrender, or abandonment of a facility, pipeline, well pad, platform, or other
21 structure, or for the restoration of a lease, field, unit, area, body of water, or right-of-
22 way in conjunction with dismantlement, removal, surrender, or abandonment, that is
23 attributable to production of oil or gas occurring before April 1, 2006; the portion is
24 calculated as a ratio of the amount of oil and gas production, in barrels of oil
25 equivalent, associated with the facility, pipeline, well pad, platform, other structure,
26 lease, field, unit, area, body of water, or right-of-way occurring before April 1, 2006,
27 to the total amount of oil and gas production, in barrels of oil equivalent, associated
28 with that facility, pipeline, well pad, platform, other structure, lease, field, unit, area,
29 body of water, or right-of-way through the end of the calendar month before
30 commencement of the dismantlement, removal, surrender, or abandonment; a cost is
31 not excluded under this paragraph if the dismantlement, removal, surrender, or

1 abandonment for which the cost is incurred is undertaken for the purpose of replacing,
2 renovating, or improving the facility, pipeline, well pad, platform, or other structure;
3 for the purposes of this paragraph, "barrel of oil equivalent" means

4 (A) in the case of oil, one barrel;

5 (B) in the case of gas, 6,000 cubic feet;

6 (16) costs incurred for containment, control, cleanup, or removal in
7 connection with any unpermitted release of oil or a hazardous substance and any
8 liability for damages imposed on the producer or explorer for that unpermitted release;
9 this paragraph does not apply to the cost of developing and maintaining an oil
10 discharge prevention and contingency plan under AS 46.04.030;

11 (17) costs incurred to satisfy a work commitment under an exploration
12 license under AS 38.05.132;

13 (18) that portion of expenditures, that would otherwise be qualified
14 capital expenditures as defined in AS 43.55.023(k), incurred during a calendar year
15 that are less than the product of \$0.30 multiplied by the total taxable production from
16 each lease or property, in BTU equivalent barrels, during that calendar year, except
17 that, when a portion of a calendar year is subject to this provision, the expenditures
18 and volumes shall be prorated within that calendar year;

19 (19) costs or that portion of the costs determined by the
20 commissioner, in consultation with the commissioner of environmental
21 conservation, the commissioner of natural resources, and the Alaska Oil and Gas
22 Conservation Commission and taking into consideration the standard practices
23 of the industry, to be

24 (A) related to the repair and replacement of property or
25 equipment that was not maintained or was improperly maintained;

26 (B) incurred to maintain the operational capability of
27 facilities or equipment shut down because of a lack of or improper
28 maintenance of property or equipment; or

29 (C) incremental operating expenses incurred as a result of
30 operating facilities or equipment at diminished capacity when that
31 diminished capacity is caused by the lack of or improper maintenance of

1 property or equipment.

2 * **Sec. 2.** The uncoded law of the State of Alaska is amended by adding a new section to
3 read:

4 APPLICABILITY. Section 1 of this Act applies to oil and gas produced after
5 March 31, 2006.

6 * **Sec. 3.** The uncoded law of the State of Alaska is amended by adding a new section to
7 read:

8 TRANSITIONAL PROVISIONS. (a) A person that filed a statement under
9 AS 43.55.030 before the effective date of this Act and deducted lease expenditures that may
10 not be deducted under AS 43.55.165(e), as amended by sec. 1 of this Act, shall file an
11 amended return and pay any additional tax within 90 days after the effective date of this Act.

12 (b) A person required to make an installment payment of estimated tax under
13 AS 43.55.020(a) for a period not included in a return required to be filed before the effective
14 date of this Act shall determine the amount of the underpayment, if any, that is attributable to
15 lease expenditures that may not be deducted under AS 43.55.165(e) as amended by sec. 1 of
16 this Act. The amount of any underpayment determined under this subsection shall be paid
17 within 90 days after the effective date of this Act.

18 * **Sec. 4.** The uncoded law of the State of Alaska is amended by adding a new section to
19 read:

20 RETROACTIVITY. Section 1 of this Act is retroactive to April 1, 2006.

21 * **Sec. 5.** This Act takes effect immediately under AS 01.10.070(c).

FISCAL NOTE

STATE OF ALASKA
2007 LEGISLATIVE SESSION

Fiscal Note Number: HB128-DOA-AOGCC 2-28-07
 Bill Version: HB128
 () Publish Date: _____

Revision Date/Time (Note if correction): _____

Dept. Affected: Administration

Title: Oil and Gas Production Tax

RDU: AOGCC

Component: AOGCC

Sponsor: Representatives Olson, Harris, Ramras, et. Al.

Requester: House Oil and Gas

Component No. 2010

Expenditures/Revenues

(Thousands of Dollars)

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

OPERATING EXPENDITURES	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Personal Services	0.0	0.0	0.0	0.0	0.0	0.0
Travel	0.0	0.0	0.0	0.0	0.0	0.0
Contractual	250.0	250.0	250.0	250.0	250.0	250.0
Supplies	0.0	0.0	0.0	0.0	0.0	0.0
Equipment	0.0	0.0	0.0	0.0	0.0	0.0
Land & Structures	0.0	0.0	0.0	0.0	0.0	0.0
Grants & Claims	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING	250.0	250.0	250.0	250.0	250.0	250.0

CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
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CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0
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FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts	0.0	0.0	0.0	0.0	0.0	0.0
1003 GF Match	0.0	0.0	0.0	0.0	0.0	0.0
1004 GF	0.0	0.0	0.0	0.0	0.0	0.0
1005 GF/Program Receipts	0.0	0.0	0.0	0.0	0.0	0.0
1037 GF/Mental Health	0.0	0.0	0.0	0.0	0.0	0.0
1162 AOGCC Receipts	250.0	250.0	250.0	250.0	250.0	250.0
TOTAL	250.0	250.0	250.0	250.0	250.0	250.0

Estimate of any current year (FY2007) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2008 budget proposal: ☐

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

If HB128 is passed the AOGCC in conjunction with other State agencies would be charged with determining whether the lease expenditures incurred for repair, replacement, or incremental operating expenses were as a result of a lack of or improper maintenance of property or equipment. The Commission would also need authority under AS 31.05.030 to implement these need responsibilities.

1 contract Engineering Investigator for 2/3 of year, which equals \$250,000 a year.

Prepared by: Jody J. Colombie, Special Assistant I
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 Approved by: Rachael Petro, Deputy Commissioner
 Agency: Department of Administration

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 Date 2/28/07 10:00 AM