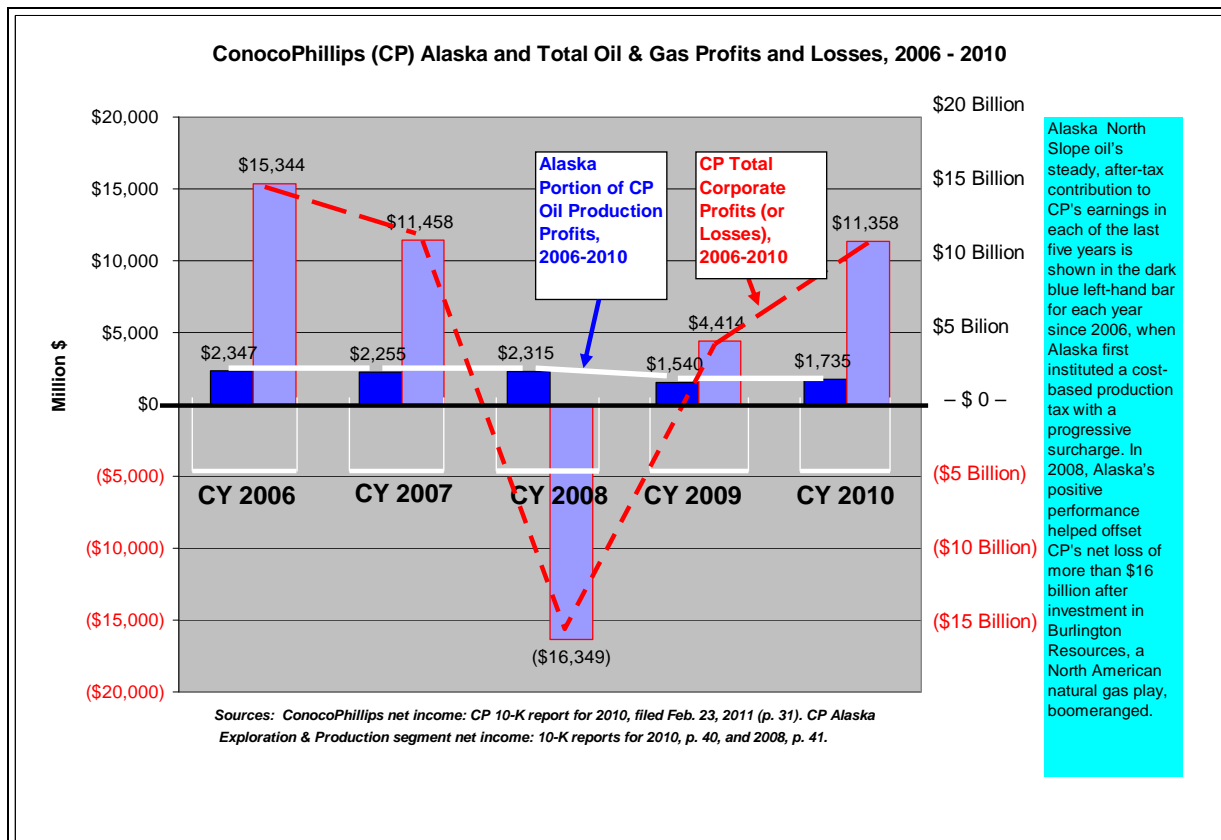


Establishing a Rational Foundation For Review, Formulation and Implementation Of Alaska's Oil and Gas Fiscal Policy

A Report by

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I. Starting Points

The impetus for this report is Governor Sean Parnell's call for swift passage of HB110 to reduce the state's cost-based production tax. The governor hopes that this change might make Alaska more competitive and induce more North Slope drilling. Otherwise, he warns, "[w]e're at risk of seeing irrevocable production decline, which threatens our pipeline. Our state needs to increase our competitiveness and grow our economy."¹ The crucial connection to TAPS was at center stage when Alyeska Pipeline Service Company President Tom Barrett appeared before the House Finance Committee March 18. Describing the temporary TAPS shutdown in January of this year as a precursor to the possible end of North Slope production due to Alyeska's inability to handle low throughput, Barrett urged legislators to act immediately to avert the problem by taking action to put more oil in the pipeline.²

Proponents of the proposed production tax reduction argue that the progressivity factor, enacted in 2006 with the shift to a cost-based tax and increased in 2007, takes such an inordinate share of revenue at high oil prices that the state must ratchet that tax down – immediately and drastically.³ A business-oriented coalition has jumped squarely on board this train. According to former University of Alaska President Mark Hamilton, "[t]he

¹ Statement of Gov. Sean Parnell, March 1, 2011 (<http://gov.alaska.gov/parnell/press-room/full-press-release.html?pr=5666>).

² Alan Bailey and Kristen Nelson, "Cooling of low-flow oil could disrupt pipeline operations – TAPS: Alyeska chief warns of impending catastrophe for Alaska," *Petroleum News*, March 27, 2011, p. 10 (and *Anchorage Daily News*, Mar. 26, 2011). See Sec. IV-B. for further discussion.

³ Whether or not the industry helped set this tax cut campaign in motion, with the recent presentations of ConocoPhillips officials, it is now clear that the industry has joined the parade of tax cut advocates.

choice is big money now, and no future, or a sustained economy that will provide more jobs and keep our workers and our children here.”⁴

Many of the arguments set forth by the supporters of HB110 fail to recognize the premises that underlie the establishment of the ACES tax regime and the complexities and the arcane geologic and economic factors that cloud the oil investment arena. Different companies take different approaches to the twin uncertainties that confront oil developers: the realities beneath the surface of the earth and the path of future oil prices. Exactly how corporations deal with and these volatile variables to arrive at investment decisions are matters of speculation. Against this complicated backdrop, rational discourse is made more difficult by the anxiety that has accompanied reduced North Slope production and throughput on TAPS, as well as the failure to recognize important lessons from the state’s North Slope development history and shortcomings in the state’s administrative system and its information base.

In an effort to provide a rational foundation for dialogue on Alaska’s petroleum fiscal policy, special attention will be given to the public disclosures of ConocoPhillips (CP) for two principal reasons:

- CP is one of three companies that, together, control roughly 95 percent of Alaska North Slope (ANS) oil crude oil production and own a roughly similar percentage of the Trans-Alaska crude oil Pipeline System (TAPS).⁵
- Under federal reporting requirements, CP reports publicly information relevant to its Alaska operations and, therefore, to Alaska’s tax policy deliberations. However, neither of the other two similarly situated companies – ExxonMobil and BP – are required to break out the performance of their Alaska holdings.⁶

⁴ See, for example, Dan Joling (Associated Press), “Business coalition urges Alaska oil tax fix,” *Washington Examiner*, Feb. 23, 2011.

⁵ CP, which produces nearly 40% of North Slope crude oil and owns approximately 28.3% of the Trans-Alaska Pipeline System (TAPS), is among the largest companies on the *Fortune 500* and the smallest of the three major transnational oil companies on the North Slope.

⁶ Because CP is significantly smaller than the BP and ExxonMobil, CP’s Alaska holdings therefore comprise a relatively larger portion of its holdings, triggering SEC disclosure requirements under Securities and Exchange Commission and Federal Accounting Standards Board guidelines (codified as SFAS 69).

This report does not intend to single out CP’s conduct for criticism. However, CP is frequently mentioned because its required disclosures to SEC, key portions of which will be discussed in subsequent sections of this report, have generated data of use for public policy

The following background information is offered to supplement and help the reader assess the significance of the facts, findings and recommendations presented in this report:

In view of the large capital investment necessary to develop and bring northern resources to market, large corporations are likely to be involved in Arctic development. For this reason, it is not surprising that forty years after discovery of the largest oil field in North America at Prudhoe Bay, all three of the major North Slope players show up high on the corporation listings. In 2009, ExxonMobil ranked second on the *Fortune 500* in gross revenue (\$285.1 billion) and led the nation in profits (\$19.3 billion). BP, a British corporation, is not tracked on the *Fortune* U.S. listing, shows up just behind ExxonMobil in the top 10 of the magazine's Global 500, ranking fourth in both revenues (\$284.6 billion) and profits (\$16.6 billion). CP's gross revenue (\$139 billion) ranked sixth in the U.S. and 17th globally in 2009, while that company's net profits, notably erratic in the last three years (see discussion in the next session) ranked 28th in the U.S.⁷

In response to the hue and cry for tax reduction at this time, the following introductory comments represent my understanding of the views that prevailed during the October-November 2007 special legislative session, when the ACES production tax regime was enacted.⁸ That measure featured trade-offs that enhance Alaska's competitive position by cushioning the industry on the downside of volatile oil prices in three significant ways:

analysis. Other facts and factors, largely overlooked in current dialogue over HB 110, will also be addressed.

⁷ See: "Top Companies: Most profitable," *Fortune*, May 3, 010 (http://money.cnn.com/magazines/fortune/fortune500/2010/full_list/) and "GLOBAL 500: Our annual ranking of the world's largest corporations," *Fortune*, July 26, 2010 (<http://money.cnn.com/magazines/fortune/global500/2010/>).

⁸ These general comments reflect my first-hand understandings of the prevailing views expressed at the time. (I participated in the ACES process as a consultant to the Alaska Department of Revenue during the creation of the ACES proposal and the special session during which the proposal was significantly modified and adopted. It should be noted, however, that during the ACES Special Session in 2007 my efforts were almost solely focused on the section of that bill that dealt with Trans-Alaska Pipeline System tariffs [enacted as AS 43.55.150]. I did not work on the tax rate or progressivity elements (which I now defend) and cannot claim credit – or blame – for them.)

- Because the state's production tax is now cost-based, the industry pays taxes on North Slope production only on revenues in excess of incurred costs, and only after the company has recouped its costs. For this reason, many in the industry supported switching to a cost-based tax just as the progressivity feature increases the tax bite as oil prices rise, declining prices reduce the tax bite.
- Just as the progressivity feature increases the tax bite as oil prices rise, declining prices reduce the tax bite.
- The panoply of production tax credits offered with the institution of the cost-based, progressive production tax offers potential explorers and developers early pay-back on expenditures, significantly reducing investment risk.

The state instituted these measures in 2006 and 2007 to share downside risks in response to the industry's desire to reduce investor exposure to volatile oil prices. In exchange, when rising oil prices create windfall profits for the industry, the progressivity factor the Legislature put into place with ACES in 2007 enables the state take in a larger portion of that windfall revenue. In this case, the industry still receives an increase in after-tax revenues without additional investment.

From the standpoint of state fiscal policy, through the progressive production tax structure the state receives surplus revenue when oil prices rise, retaining surplus revenue for use, as necessary, when revenues slump. The ACES tax framework is consistent with principal revenue collection, retention and disposition mechanisms.⁹ Some observers may find it strange that the state government, having re-crafted its tax policy to be responsive to volatile oil prices and changing conditions in the petroleum world by sharing low-price risk, is now being asked to consider giving up revenue at high oil prices in hopes of inducing increased exploration and development. Some critics of HB 110 believe that instead of reducing production taxes, it might make more sense – and would be more consistent with generally accepted policy – to continue with the existing system, let the industry decide whether or not to take risks and focus instead on fixing weaknesses in the state's oil and gas management system.

⁹ The Alaska Permanent Fund, established in 1976, and the Constitutional Budget Reserve Fund, established in 1990, manifest this philosophy.

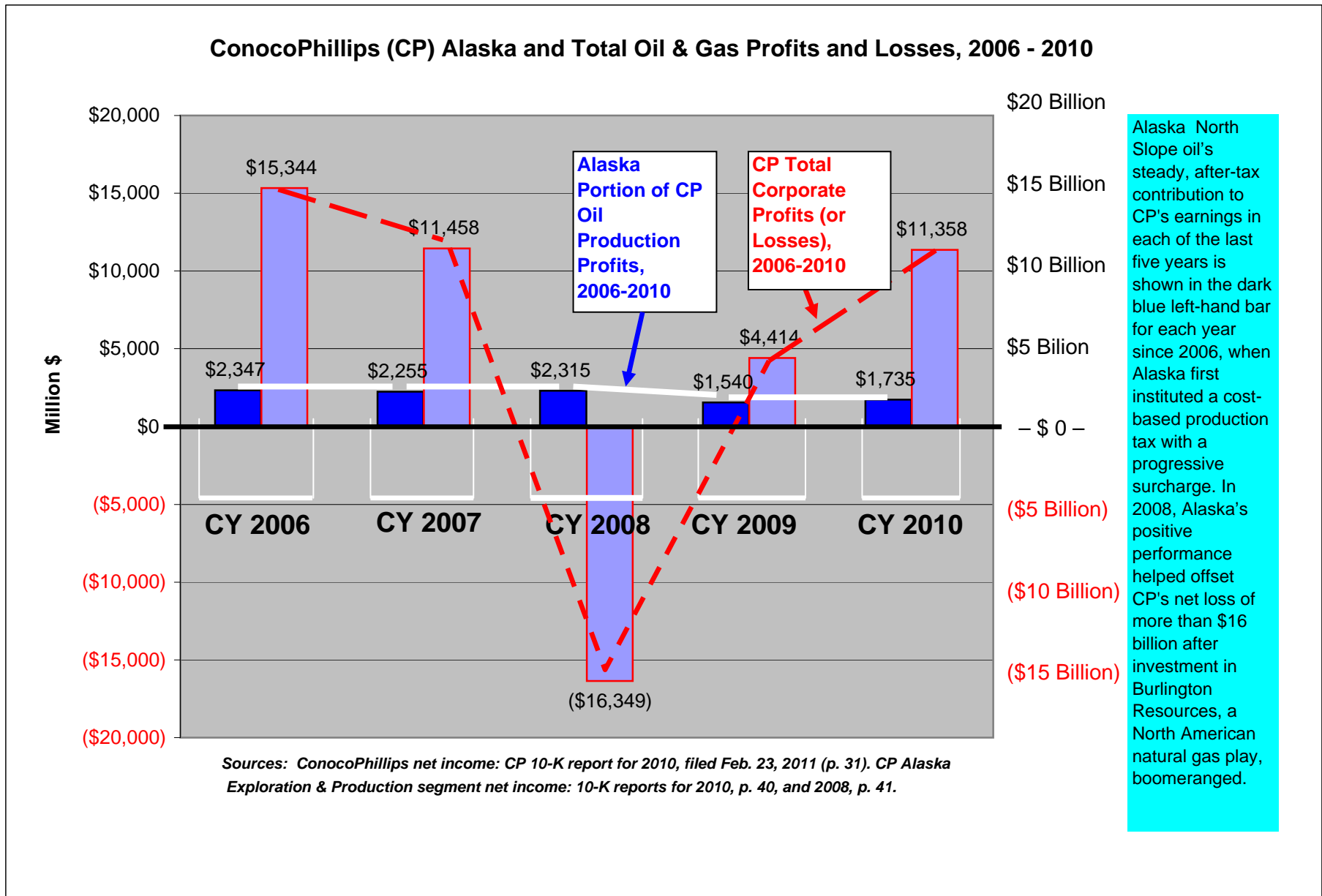
Corporations would be happy to *receive* free money, but it does not necessarily follow that reducing production tax would induce them to *spend* more money in Alaska to spur more aggressive exploration and development. As the current tax debate has unfolded, some state legislators have correctly observed that declines in both the North Slope production and exploration efforts pre-date the institution of the cost-based production tax instituted in 2006 and 2007. This historical look at petroleum development in Alaska challenges the assertion that the increased bite of the cost-based production tax is responsible for the recent decline in exploratory drilling.

II. The ConocoPhillips Profitability Record

Figure 1, on the following page, suggests that Alaska continues to be a good place for CP to invest. This chart, assembled from recent CP data, compares the company's profits from Alaska since 2006 to its overall performance. As shown in Figure 1, in contrast to CP's worldwide suite of investments, Alaska has been a consistent profit-maker since 2006 (the year that Alaska initiated the cost-based production tax regime the state administration now seeks to modify). This fact was shown most clearly in 2008, when Alaska's continued positive contribution to CP's coffers helped offset CP's whopping overall loss of nearly \$17 billion.¹⁰

¹⁰ A major cause of CP's overall loss in 2008 was that company's write-down of its 2005 investment in Burlington Resources. According to *Fortune*, that natural gas play that proved disastrous when natural gas prices collapsed to one-third the prevailing price when CP purchased Burlington Resources. (See: "4. ConocoPhillips (*Fortune* 500 listing, 2009; <http://money.cnn.com/magazines/fortune/fortune500/2009/snapshots/327.html>.)

Figure 1.



As reported by CP, its Alaska exploration and production profits include both oil and gas production. The reported profit figures therefore include CP's 70% share in Cook Inlet liquefied natural gas (LNG) export to Asia.¹¹ In light of the facts that natural gas prices significantly lag oil and CP has announced the shutdown of the Cook Inlet LNG facility after 40 years of operation, it appears that the Cook Inlet contribution to CP's Alaska profits is declining; in this case, the North Slope oil share of reported profits would be increasing.

Further support for the ACES progressivity structure from the producer's perspective can be derived from the operating data from which the summary results in Figure 1 were taken. Between 2008 and 2010, CP's reported annual production profits from Alaska averaged between between 25.5% and 27.4% of the company's total annual expenditures. Most significantly, as oil prices rose in 2010, so did CP's share of net revenue from its Alaska operations. In contrast, CP's rest-of-world results were erratic.¹²

In sum, the current (2006 – 2010) CP operating data under the current ACES tax regime, as shown in Figure 1, cast serious doubt on the putative need to reduce state production tax progressivity.

¹¹ Precise separation of CP's Alaska oil and gas components was not possible. However, it is estimated that natural gas production to barrels of oil equivalent indicates that approximately 90 percent of CP's Alaska revenue is from North Slope oil.

¹² For 2008 through 2010, here are the figures CP reported:

CP Exploration & Production	2008	2009	2010	Total
<u>Alaska</u>				
Total Expenditures + Taxes	\$9,9190	\$5,644	\$6,338	\$21,172
Net Income	\$2,315	\$1,540	\$1,735	\$5,590
Net Income (as % of Total Expenditures + Taxes)	25.2%	27.3%	27.4%	26.4%
<u>Rest of World (excl. Alaska)</u>				
Total Expenditures + Taxes	\$35,535	\$21,421	\$28,942	\$85,898
Net Income	\$9,506	\$1,962	\$7,647	\$19,115
Net Income (as % of Total Expenditures + Taxes)	26.8%	9.2%	26.4%	22.3%

See: ConocoPhillips, "Results of Operations," *10-K Annual report pursuant to section 13 and 15(d)*, Feb. 23, 2011, pp. 149-151 (excerpted pages in Appendix D at back of this report).

One analyst, citing the CP data set from which Figure 1 was derived, has suggested that a principal reason investment in Alaska petroleum development has slowed is that when oil prices rise, the progressive ACES production tax regime shrinks the percentage of the additional income that companies retain.¹³ From a bottom-line perspective, in the case of a short-term price oil price increase the industry takes in additional revenue without incurring additional costs. The recipient of this windfall would be unlikely to focus on the fact that the state takes a larger share of the marginal pre-tax income from higher oil prices (an ACES trade-off, as noted above, for the state's willingness to share the investor's low-price risk).

Based on Figure 2A on the following page, when the price of oil increases from \$80 to \$90 per barrel under the existing ACES regime, industry after-tax profits increase by approximately \$1.97 / bbl. Annualized, I estimate that this price increase would yield increased industry profits of approximately \$467 million – more than \$50,000 per hour.¹⁴

In this example, operating and capital costs (currently estimated to comprise approximately one-third of the market price of oil and three times the amounts projected when PPT was adopted in 2006), are held constant, reflecting the assumption that this price spike did not further increase field costs.

¹³ See: Roger Marks, "Evaluation of ACES with HB 110 Proposal," March 15, 2010, on-line slide #13, (presentation to the House Finance Committee).

¹⁴ This model may differ from those typically used by government personnel in three key respects:

(1) A transportation profit element is added to industry profits at Line 6 and details of this tax calculation are noted so that policy makers will be able to recognize and consider transportation cost impacts on bottom-line results.

(2) a tax credit is inserted at Line 11d for addition to industry profits (prior to calculation of state and federal income tax); this element is added to industry profits at Line 13 and is also subtracted from state total revenue at Line 14a.

[Both of these items are rough estimates.]

(3) Federal income tax is estimated at an effective tax rate of 21% rather than the nominal rate (35%). (For discussion of differing federal tax rates, see: Richard A. Fineberg, *The Profitability and Economic Viability of Alaska North Slope and Associated Pipeline Operations*, April 27, 2005 [prepared for the Prince William Sound Regional Citizens' Advisory Council], pp. 55-58.)

Figure 2A

ACES at \$80 and \$90 per Barrel: Estimated Bottom-Line and Marginal Net Revenue Take

		ANS Crude Oil Market Price		
Steps To Estimate Net Revenue Take per barrel and Annualized Results		\$80/bbl.	\$90/bbl	How Calculated
(1)	ANS Sales Price (\$ / bbl.)	\$80.00	\$90.00	Assumed ANS Market Price
(2)	ANS Production (Million Bbl/Yr)	237.3	237.3	(650,000 bpd * 365)
(3)	Gross Production Value (Million \$)	18,980.0	21,352.5	Line (2) * Line (3)
(4)	Est. Marine + N. Slope "Feeder" P/L Tariffs (\$ / bbl.)	\$2.21	\$2.21	ADOR, "Oil and Gas Production Tax Status Report to the Legislature," Jan. 18, 2011 (Chart 4)
(5)	Estimated TAPS Tariff (\$ / bbl.)	\$3.81	\$3.81	ADOR, "Oil and Gas Production Tax Status Report to the Legislature," Jan. 18, 2011 (Chart 4)
(6)	Est. Transportation Profit (2.00/bbl.)	\$2.00	\$2.00	Estimate for addition to state and federal income tax bases (lines 11 and 12)
(7)	Estimated Production Costs (Operating + Capital; \$ / bbl.)	\$23.00	\$23.00	\$80/bbl.: ADOR, <i>Fall 2010 Revenue Sources</i> , p. 36 (FY 2011 est. OPEX and CAPEX: \$11.40 each)
(8)	Total Costs – \$/bbl.	\$29.02	\$29.02	(Line 4) + (Line 5) + (Line 7)
(9)	Wellhead Price (\$/bbl.)	\$50.98	\$60.98	(Line 1) - (Line 8)
(10)	Production Tax Calculation (\$/bbl. or %):			
a.	Production Cost for Calculating ACES	\$26.29	\$26.29	(Line 7) / 0.875 (see notes below)
b.	ACES Tax Base	\$53.71	\$63.71	(Line 1) - (Line 10a)
c.	Progressivity Surcharge Base	\$23.71	\$33.71	(Line 10a) - \$30.00 per barrel (per statute)
d.	Progressivity Tax Factor	9.49%	13.49%	(Line 10c) * 0.4% (per statute)
e.	Production Tax Rate	34.49%	38.49%	25% + (Line 10d)
f.	Production Tax	\$18.52	\$24.52	(Line 10b) * (Line 10e)
(11)	State ANS Production & Pipeline Revenue – \$ / bbl.:			
a.	Royalty	\$6.37	\$7.62	(Line 9) * 0.125
b.	Est. Total State & local Property Tax (Production + TAPS)	\$1.26	\$1.26	Estimated annual TAPS and North Slope property tax (includes municipalities shares)
c.	Production Tax	\$18.52	\$24.52	Line 10f
d.	Tax Credits	\$2.00	\$2.00	Estimate does not represent actual credits (see notes below).
e.	Estimated State Income Tax (Total)	\$2.71	\$2.97	0.094 * (((Line 6) + (Line 9) + (Line 11D)) - ((Lines 11a + 11b + 11c)))
(12)	Estimated Federal Income Tax (Production + Transportation) – \$ / bbl.	\$5.48	\$6.01	0.21 * (((Line 6) + (Line 9) + (Line 11D)) - ((Lines 11a + 11b + 11c + 11e)))
(13)	Estimated Industry Net Profit (Production + Transportation) – \$ / bbl.	\$20.63	\$22.60	(Lines 1 + 6 + 36 - (Lines 9 + 11a + 11b + 11c + 12 + 13))
Results				
(14)	Production and Pipeline Net Revenue Split – \$ / bbl.:			
a.	Total State Share (Production + P/L)	\$26.87	\$34.38	(Lines 11a + 11b + 11c + 11e - (Line 11d))
	State Percentage	50.7%	54.6%	(Line 14a) / (Lines 14a + 14b + 14c)
b.	Federal Revenue	\$5.48	\$6.01	Line 12
	Federal Percentage	10.3%	9.5%	(Line 14b) / (Lines 14a + 14b + 14c)
c.	Total Industry Profits (Production + Transportation)	\$20.63	\$22.60	Line 13
	Industry Percentage	38.9%	35.9%	(Line 14b) / (Lines 14a + 14b + 14c)
(15)	Annual Industry Revenue under ACES – \$ Millions	\$4,893.8	\$5,361.2	(Line 14c) * (Line 2)
(16)	Annual Industry Revenue Gain under ACES (\$90.00 / bbl. v. \$80.00 / bbl.) – \$ millions		\$467.5	(Line 15 @ \$90.00/bbl.) - (Line 15 @ \$80.00/bbl.)

Notes:

- Line 6: Independent shippers pay pipeline tariffs out of pocket; for the major TAPS owners, who produce and transport roughly similar shares of North Slope crude oil, pipeline tariff charges represent a transfer payment between subsidiaries. The transportation profit element, roughly estimated, is re-inserted at Lines 11b, 12 and 13 to calculate total industry profits and state and federal income taxes more accurately. (This \$2.00/bbl. figure is a rounded estimate, provided for illustrative purposes to note that TAPS owners realize a guaranteed profit on TAPS shipments.)
- Line 10a: This calculation reflects the fact that the ACES regime increases the allowable per-barrel cost deduction by one-seventh because the statute only covers non-royalty barrels.
- Line 10c: Effective rates calculated here match ACES rates shown by R. Marks, "Evaluation of ACES with HB 110 Proposal (March 15, 2011), slides 3, 4 and 32.
- Lines 11b, 11d: Detailed analysis of tax credits is beyond the scope of this worksheet. As noted at Line 6, these are rough estimates provided for illustrative purposes.
- Line 12: The 21% federal income tax rate used for this calculation, represents an approximation. See Fineberg, *The Profitability and Economic Viability of Alaska North Slope and Associated Pipeline Operations* (Prince William Sound Regional Citizens' Advisory Council, 2005), pp. 55-61, for discussion and additional data.
- Line 13: The \$10.00 per barrel price increase modeled here results in an Industry net profit increases by \$1.97 per barrel, realized without additional cash outlays.

This is the take-away message from Figure 2A: When oil production is already profitable, a short-term increase in high oil prices creates windfall profits – additional profit without additional investment – for the producer.

Even if field costs go up, under ACES everybody on the producing end wins. Figure 2B looks at the possibility that if the \$90.00 / bbl. price held for a year, field costs might also rise. If additional field costs of (say) \$3.00 / bbl. were reported as prices remained high, the ACES field cost allowance would reduce the state production tax bite so that the industry, under ACES, would still retaining an additional \$1.62 / bbl. from the \$10.00 / bbl. increased oil price at \$22.25 / bbl (down from \$22.60 / bbl.). At that rate for an entire year, the industry would gain approximately \$386 million – about \$44,000 per hour.

The state, with a \$2.57 / bbl. cut in its progressive gain, would shoulder the preponderance of the \$3.00 / bbl. cost increase but would still realize an increase of \$4.94 / bbl. (\$1.25 billion). Just as the state gains on the high side when oil prices rise, those gains are backed off when oil prices decline. As noted at the outset of this report, the state's larger share of windfalls can be understood as a trade-off for industry-friendly tax mechanisms that include capital credits and deferred revenue collections at low oil prices.

An important feature of this model is that it separates transportation profits from production profits. Through this reporting mechanism, the effects of overlapping ownership of production and transportation facilities (a characteristic of vertical integration) can be observed.¹⁵

¹⁵ The \$2.00 / bbl. transportation profit estimate used in this example includes pipeline and marine transportation (tanker) elements. In addition to TAPS, pipeline tariff profits include regulated North Slope feeder pipelines. It should be noted that tariffs are the subject of litigation and profit data are not readily available.

Figure 2B

ACES at \$80 and \$90 per Barrel: Estimated Bottom-Line and Marginal Net Revenue Take (Cost Increase Scenario)

		ANS Crude Oil Market Price		
<u>Steps To Estimate Net Revenue Take per barrel and Annualized Results</u>		<u>\$80/bbl.</u>	<u>\$90/bbl</u>	<u>How Calculated</u>
(1)	ANS Sales Price (\$ / bbl.)	\$80.00	\$90.00	Assumed ANS Market Price
(2)	ANS Production (Million Bbl/Yr)	237.3	237.3	(650,000 bpd * 365)
(3)	Gross Production Value (Million \$)	18,980.0	21,352.5	Line (2) * Line (3)
(4)	Est. Marine + N. Slope "Feeder" P/L Tariffs (\$ / bbl.)	\$2.21	\$2.21	ADOR, "Oil and Gas Production Tax Status Report to the Legislature," Jan. 18, 2011 (Chart 4)
(5)	Estimated TAPS Tariff (\$ / bbl.)	\$3.81	\$3.81	ADOR, "Oil and Gas Production Tax Status Report to the Legislature," Jan. 18, 2011 (Chart 4)
(6)	Est. Transportation Profit (2.00/bbl.)	\$2.00	\$2.00	Estimate for addition to state and federal income tax bases (lines 11 and 12)
(7)	Estimated Production Costs (Operating + Capital; \$ / bbl.)	\$23.00	\$26.00	\$80/bbl.: ADOR, <i>Fall 2010 Revenue Sources</i> , p. 36 (FY 2011 est. OPEX and CAPEX: \$11.40 each) \$90/bbl.: ADOR, <i>Fall 2010 Revenue Sources</i> + \$3.00 per barrel
(8)	Total Costs – \$/bbl.	\$29.02	\$32.02	(Line 4) + (Line 5) + (Line 7)
(9)	Wellhead Price (\$/bbl.)	\$50.98	\$57.98	(Line 1) - (Line 8)
(10)	Production Tax Calculation (\$/bbl. or %):			
a.	Production Cost for Calculating ACES	\$26.29	\$29.71	(Line 7) / 0.875 (see notes below)
b.	ACES Tax Base	\$53.71	\$60.29	(Line 1) - (Line 10a)
c.	Progressivity Surcharge Base	\$23.71	\$30.29	(Line 10a) - \$30.00 per barrel (per statute)
d.	Progressivity Tax Factor	9.49%	12.11%	(Line 10c) * 0.4% (per statute)
e.	Production Tax Rate	34.49%	37.11%	25% + (Line 10d)
f.	Production Tax	\$18.52	\$22.37	(Line 10b) * (Line 10e)
(11)	State ANS Production & Pipeline Revenue – \$ / bbl.:			
a.	Royalty	\$6.37	\$7.25	(Line 9) * 0.125
b.	Est. Total State & local Property Tax (Production + TAPS)	\$1.26	\$1.26	Estimated annual TAPS and North Slope property tax (includes municipalities shares)
c.	Production Tax	\$18.52	\$22.37	Line 10f
d.	Tax Credits	\$2.00	\$2.00	Estimate does not represent actual credits (see notes below).
e.	Estimated State Income Tax (Total)	\$2.71	\$2.92	0.094 * (((Line 6) + (Line 9) + (Line 11D)) - ((Lines 11a + 11b + 11c)))
(12)	Estimated Federal Income Tax (Production + Transportation) – \$ / bbl.	\$5.48	\$5.92	0.21 * (((Line 6) + (Line 9) + (Line 11D)) - ((Lines 11a + 11b + 11c + 11e)))
(13)	Estimated Industry Net Profit (Production + Transportation) – \$ / bbl.	\$20.63	\$22.25	(Lines 1 + 6 + 36 - (Lines 9 + 11a + 11b + 11c + 12 + 13))
Results				
(14)	Production and Pipeline Net Revenue Split – \$ / bbl.:			
a.	Total State Share (Production + P/L)	\$26.87	\$31.81	(Lines 11a + 11b + 11c + 11e - (Line 11d))
	State Percentage	50.7%	53.0%	(Line 14a) / (Lines 14a + 14b + 14c)
b.	Federal Revenue	\$5.48	\$5.92	Line 12
	Federal Percentage	10.3%	9.9%	(Line 14b) / (Lines 14a + 14b + 14c)
c.	Total Industry Profits (Production + Transportation)	\$20.63	\$22.25	Line 13
	Industry Percentage	38.9%	37.1%	(Line 14b) / (Lines 14a + 14b + 14c)
(15)	Annual Industry Revenue under ACES – \$ Millions	\$4,893.8	\$5,279.9	(Line 14c) * (Line 2)
(16)	Annual Industry Revenue Gain under ACES (\$90.00 / bbl. v. \$80.00 / bbl.) – \$ millions		\$386.2	(Line 15 @ \$90.00/bbl.) - (Line 15 @ \$80.00/bbl.)

Notes: (\$90.00/bbl. scenario modeled with a \$3.00 / bbl. cost increase.)

- Line 6: Independent shippers pay pipeline tariffs out of pocket; for the major TAPS owners, who produce and transport roughly similar shares of North Slope crude oil, pipeline tariff charges represent a transfer payment between subsidiaries. The transportation profit element, roughly estimated, is re-inserted at Lines 11b, 12 and 13 to calculate total industry profits and state and federal income taxes more accurately. (This is a rounded estimate, provided for illustrative purposes to note that TAPS owners realize a guaranteed profit on TAPS shipments.)
- Line 10a: This calculation reflects the fact that the ACES regime increases the allowable per-barrel cost deduction by one-seventh because the statute only covers non-royalty barrels.
- Line 10c: Effective rates calculated here match ACES rates shown by R. Marks, "Evaluation of ACES with HB 110 Proposal (March 15, 2011), slides 3, 4 and 32.
- Lines 11b, 11d: Detailed analysis of tax credits is beyond the scope of this worksheet. As noted at Line 6, these are rough estimates provided for illustrative purposes.
- Line 12: The 21% federal income tax rate used for this calculation, represents an approximation. See Fineberg, *The Profitability and Economic Viability of Alaska North Slope and Associated Pipeline Operations* (Prince William Sound Regional Citizens' Advisory Council, 2005), pp. 55-61, for discussion and additional data.
- Line 13: The \$10.00 per barrel price increase modeled here results in an Industry net profit increases by \$1.97 per barrel, realized without additional cash outlays.

These worksheets demonstrate the complexity of the factors at play as the critical numbers go into the oil revenue number-crunching machine and interact to produce bottom-line revenue figures – and the need to apply careful analysis to the oil and gas policy issues that confront Alaska. Experience dictates: When working with the complex of factors that determine the state, federal and industry shares of net revenue at varying prices, similarly detailed analyses of the bottom-line consequences should be employed to assess the significance of the points.

III. Declining North Slope Throughput and the Era of High Oil Prices

In view of the constant refrain that tax cuts are necessary to make Alaska competitive and thereby arrest the production decline that threatens to shut down the Trans-Alaska Pipeline, some observers may be surprised by the stability of CP's annual profits from North Slope crude oil production between 2006 and 2010. The tax reduction arguments rest on the notion that "Alaska is simply not competitive." Two propositions are frequently offered to support this concern:

- The Trans-Alaska Pipeline "is two-thirds empty . . . [and] may be shut down within a decade;" and
- "Investment dollars are by-passing Alaska for North Dakota, Alberta, Australia and Russia."¹⁶

Tax reduction advertisements focus also on the historical fact that TAPS throughput is down nearly 70 percent from the frequently-referenced ANS production peak of 1988 and North Slope production continues to decline (albeit more slowly than often stated).¹⁷ From a fiscal standpoint, it should be noted that the dramatic rise in oil prices that began in 1998 reflects an important, long-term upward price trend that opens the door to

¹⁶ Statements on the web site of the Make Alaska Competitive Coalition, a recently-formed *ad hoc* lobbying group. (<http://www.makealaskacompetitive.com/>).

¹⁷ There is, of course, little comfort in the fact that the North Slope decline is the natural result of the aging of Prudhoe Bay, the largest producing field in North America's history. But there is nothing new or surprising in the fact that TAPS carries much less oil than it did at its peak. (More than a quarter-century ago, in the mid-1980's, the director of the state Office of Management and Budget was trying to educate folks about the seriousness of the looming Prudhoe Bay decline, just over the horizon.)

information, presented below, that has bearing on both of the concerns of tax reduction advocates summarized in the preceding bullets.

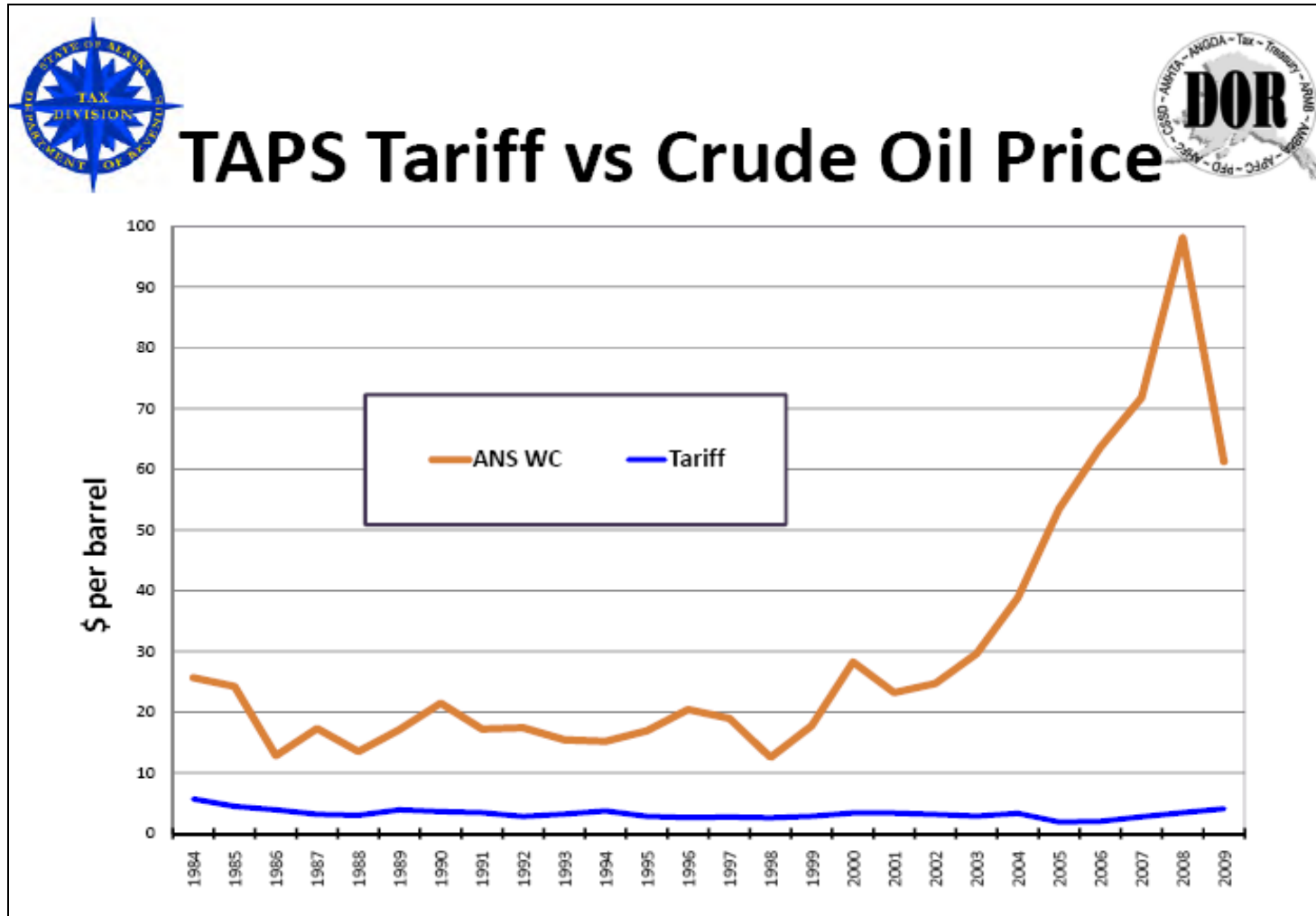
The broad dimensions of the increase in oil prices are shown in Figure 3 on the following page. This chart is particularly useful because it also displays the Trans-Alaska Pipeline System tariff, the heavy blue line running across the bottom of the page. From cursory inspection, one might be tempted to conclude that because the TAPS tariff now comprises a small fraction of the per-barrel price of oil, pipeline costs are not significant from a public policy standpoint; I beg to differ. In my estimation, the attention to TAPS in the current policy deliberations, along with the perennial and protracted bouts of legal arm-wrestling between independent shippers and industry over TAPS issues both testify to the economic importance of TAPS. (Pipeline issues will be covered in the following section.) .

The higher price of oil has significantly offset the economic effects of the reduction in the volume of oil produced and shipped from Alaska. While oil prices remain volatile, many informed observers believe that the world has entered an era that will sustain significantly higher oil prices. Support for this view is found in the strong upward trajectory of recent oil prices. Near the end of each of the last three decades, oil prices tumbled sharply. But in 2008, instead of diving toward the single-digit range and hanging out there for several months, oil prices bottomed out at a significantly higher level (just under \$40.00 / bbl. in nominal dollars), then quickly resumed an upward path. Even when adjusted for inflation, during the decade between 2000 and 2009 the rising price of oil (identified in Figure 3 as “ANS WC”) still averaged more than twice that of the preceding decade.¹⁸

¹⁸ ANS monthly price data and an inflation index (using the Gross Domestic Product [GDP] deflator) are provided for reference in Appendix B.

Figure 3

Alaska North Slope Crude Oil Price v. TAPS Tariff, 1984 – 2009
(Nominal \$ per barrel)



Alaska Department of Revenue, Presentation to Senate Finance Committee, Feb. 16, 2010 (Slide 6).

Acknowledging that “there is a lot of oil left in Alaska,” ConocoPhillips President Trond-Erik Johansen told the Fairbanks Chamber of Commerce April 5 that “as the oil prices have increased lately, that kind of oil gets more and more interesting” but “it costs much more to get it out.” Therefore, Johansen said, CP investment to produce those barrels is contingent on the state’s reduction of its production tax base.¹⁹

Mr. Johansen presented two outcomes to the policy debate over ACES revision. On one side, he said, “we have the infrastructure. . . and we have the TAPS line.” Under the right circumstances, he said, increasing TAPS throughput to 1.0 million bpd is a realistic goal.²⁰ On the other hand, he reiterated the frequently repeated concerns that Alaska was losing to North Dakota and other locales with more favorable tax climates.

Although detailed analysis of North Dakota’s oil boom is beyond the scope of this report, it can readily be observed that the large Bakken shale oil and gas reserves, now booming there, were previously identified but lay dormant for an extended period until the recent rising prices enabled the development of costly new technology.²¹ Suffice it so say that the transition to an era of higher oil prices – a world-wide phenomenon reflected in the price of ANS crude, as shown in Figure 3 – has enabled financing for the development of shale oil and gas reserves elsewhere, but it does not necessarily follow that Alaska’s fiscal regime is no longer competitive.

¹⁹ From author’s notes. (Excerpts of Johansen’s remarks can be heard at “Newscast: Wed 4/6/11 00 [Dan Bross], KUAC Local News, <http://www.publicbroadcasting.net/kuac/news.newsmain/article/0/0/1785466/KUAC.Local.News/Newscast.Wed.4611>).

²⁰ In this regard, it should be noted that the Alaska Department of Natural Resources estimates that even without continued exploration, existing North Slope fields contain an estimated 5.2 billion barrels of reserves for production between now and 2050. Alaska Department of Natural Resources, “Oil and Gas Reserves, North Slope,” *Alaska Oil and Gas Report*, November 2009 (Updated May 2010), p. 8 (Table I.1).

²¹ For background on the North Dakota boom, see: U.S. Geological Survey, *Assessment of Undiscovered Oil Resources in the Devonian-Mississippian Bakken Formation, Williston Basin Province, Montana and North Dakota, 2008 (National Assessment Oil and Gas Fact Sheet)*, April 2008, and U.S. Energy Information Administration, *Technology-Based Oil and Natural Gas Plays: Shale Shock! Could There Be Billions in the Bakken?*, November 2006.

Also on the scary side, Johansen also stressed the point that if North Slope throughput cannot be increased, cooler pipeline temperatures at low throughput rendered TAPS vulnerable to shutdown by ice or wax blockage.

To help understand – and, hopefully, resolve – questions raised by Johansen’s paradoxical presentation, in Figure 4 I have updated Figure 3 with price, field cost and transportation cost estimates. At the far right-hand side of this chart I have inserted approximations of field cost estimates (the red dotted lines near the lower right-hand corner of the chart). The yellow box that appears at the center of the revised chart provides sourcing and additional detail about the transportation and cost elements that are subtracted from the market price of crude oil to determine the net price, which serves as the production tax base. This graphic update (which utilizes the best estimates I could find for critical inputs during the early days of these hearings) provides background and perspective on the state fiscal regime, whose operation was depicted in Figure 2.

At the risk of calling attention to the obvious, I note that rising oil prices have greatly expanded empty space on the vertical axis between the TAPS tariff (at the bottom of the figure) and the volatile but upward-trending oil price (near the top); this development creates significantly more room for fighting over the division of shares or excess revenue from each barrel of that oil. To put this gap in hard-dollar terms: On average, each barrel of ANS crude produced today is accompanied by another 600,000-plus; this adds up to more than 200 million barrels per year. Therefore, if each inch on the vertical axis of Figure equals about \$30.00 per barrel, then possession of 100% of the revenue in that inch would be worth more than \$6.0 billion per year.²² Clearly, the amounts at issue on the vertical axis of this chart warrant more detailed analysis than the tax reduction proposals generally receive in the public process.

²² The gross value of that inch – approximately the drop in average price between 2008 and 2009 shown in Figure 2 – can be calculated as follows: $\$30.00 * (600,000 \text{ bbls.}) =$ approximately \$18 million per day, or \$6.57 billion (\$6,570 million) per year. With that much revenue riding on the oil price changes, one should not be surprised that the industry managers and their teams utilize aggressive accounting and reporting practices to maximize their share of price windfall gains.

Consider in this regard a claim that Johansen made on one of his charts to support his case that the Alaska's petroleum fiscal regime with the ACES tax structure was not competitive. On that slide, Johansen said that CP would lose significant amounts of money on its North Slope investments if oil prices dropped to \$50.00 / bbl. At first cut, I estimate that at that market price, a new barrel of North Slope crude oil would still show a profit under ACES after absorbing an additional capital cost of \$10.00 / bbl.²³

The 2010 addition to the oil price line that rises toward the top right corner of this chart serves as a reminder of the importance, for policy purposes, of obtaining and using the most current information available. When ADOR first presented Figure 3 early in 2010, that chart gave the impression that the price of oil was still declining, continuing the breaking in the upward trend that had prevailed since 1998. In fact, throughout 2009 oil prices had increased rather steadily, with the December 2009 average (\$75.19 per barrel) nearly doubling the January average (\$39.01).²⁴

The CY 2010 average price in Figure 4 displays the reversal of the temporary decline in average prices during the second half of 2008. While the price of oil frequently fools its forecasters, as of late March 2011, oil prices in excess of \$100 / bbl. confirm the continued upward price trend.²⁵ In this regard, it should be noted that the state's practice of relying on fiscal year data puts Alaska out of sync with the rest of the world – and, consequently, renders state analysts and policy makers vulnerable to missing or misperceiving the significance of current data.

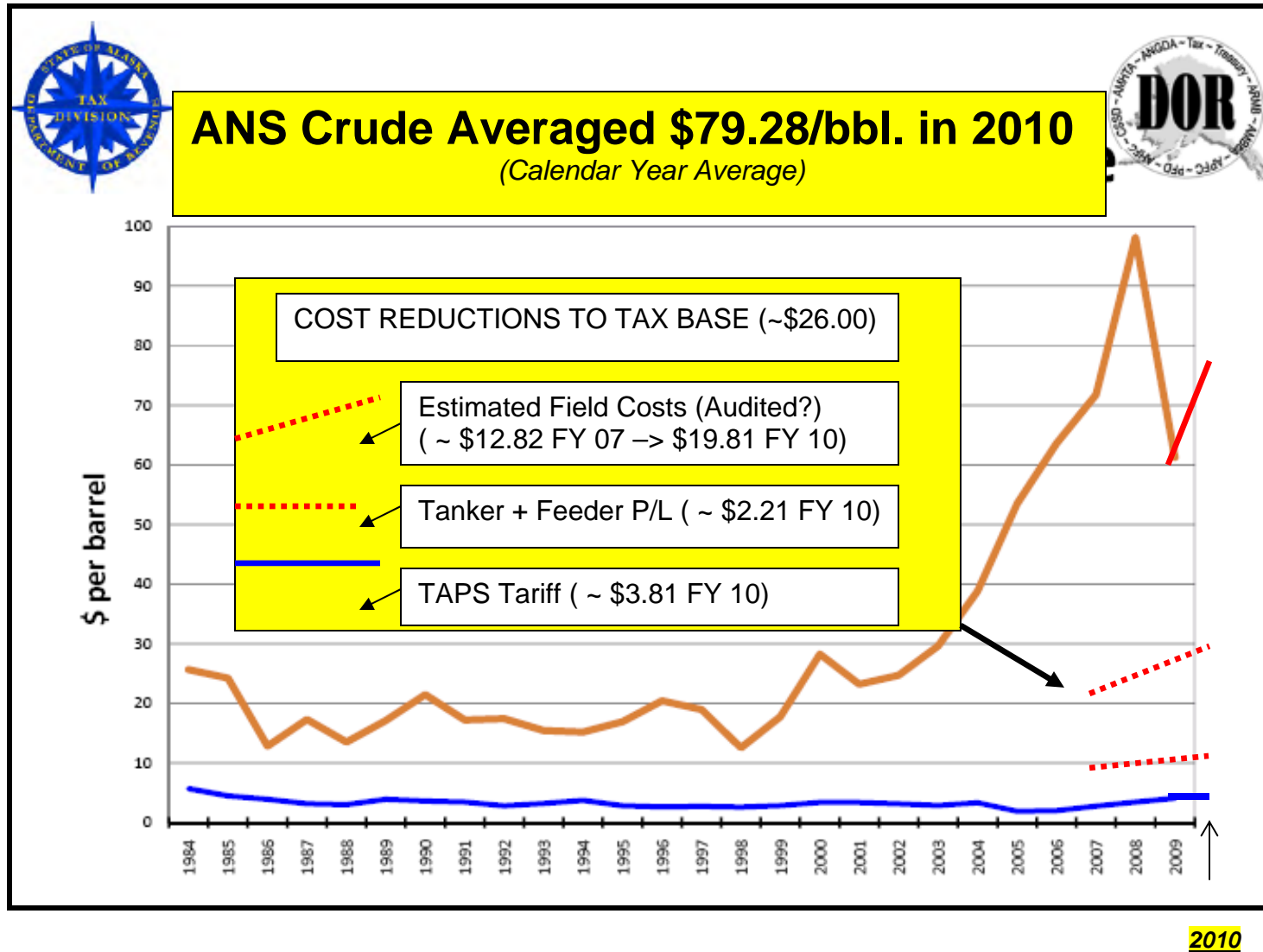
²³ I asked for copies of Mr. Johansen's slides so that I could understand the basis for the results he presented. A senior official with Mr. Johansen said the slides were on a flash drive and promised to provide them; as of this writing, they have not yet arrived. I therefore offer this observation provisionally and will correct it if I find I have misread or misunderstood the data Mr. Johansen presented.

²⁴ Examination of the monthly prices reported in Appendix B indicates that during 2009 the monthly average price increased over the prior month by an average of nearly \$6.00 per barrel during eight months, declining in the remaining four months by an average of approximately \$2.50 per barrel.

²⁵ During the last week ANS has averaged approximately \$117.00 /bbl. on the West Coast. (Alaska Dept. of Revenue, "Crude Oil Prices – Bloomberg" [<http://www.tax.alaska.gov/programs/oil/dailyoil/dailyoil.aspx>].)

Figure 4

Alaska North Slope Crude Oil: Updating ADOR's Chart with 2010 Price and Cost Data
(Nominal \$ per barrel)



Sources: Alaska Department of Revenue, *Oil and Gas Production Tax Status Report to the Legislature*, Jan. 18, 2011 (Chart 4 [field costs]), *Fall 2010 Revenue Sources Book* (Appendix Table B-2a [tanker and tariff estimates]) and web site [oil prices].
– Compiled by Research Associates, Ester, Alaska (February 2011)

The largest pre-tax elements filling the gap in Figure 4 between the price of oil (averaging \$79.28/bbl. in 2010) are the operating and capital field production costs (identified in this chart as increasing from approximately \$12.82 in fiscal year 2007 to \$19.81 in fiscal year 2010).²⁶ These costs double to triple the transportation costs shown here (depending on which year's estimate one uses) and constitute significant cost deductions under the PPT and ACES production tax regimes instituted, respectively, in 2006 and 2007. These costs were further increased in hearing presentations last month, when updated exemplary slides featured production costs of \$23.00 to \$26.00 per barrel.²⁷

These striking cost increases are consistent with a national trend that represent a striking reversal from two decades of production cost declines.²⁸ When the state adopted the first cost-based production tax in 2006, total production costs for FY 2008 were estimated at \$7.27 per barrel; fifteen months later, when the ACES revision was passed in November 2007, the FY 2008 cost estimate had doubled, to \$14.56.²⁹ Reported ANS costs are currently running some 55% to 80% over the doubled figure. In

²⁶ The Department of Revenue's estimated FY 2010 operating and capital costs were presented in the Alaska Department of Revenue *Fall 2010 Revenue Sources Book*, and in a January 2011 report to the Legislature, mandated in 2006 with the passage of the cost-based PPT, to review and present findings on the impact of the production tax changes prior to the 2011 legislative sessions (Commissioner Bryan Butcher [Alaska Dept. of Revenue], "Oil and Gas Production Tax Status Report to the Legislature," Jan. 18, 2011, p. 1 and slide 4).

²⁷ See: Roger Marks, "History of Alaska's Oil & Gas Production (Severance) Tax," Feb. 9, 2011 (presentation to the House Resources Committee), on-line slide #8 and "Evaluation of ACES with HB 110 Proposal," March 15, 2010, on-line slide #3 and 24, (presentation to the House Finance Committee). Marks sources the Feb. 9 \$23.00 / bbl. estimate to the Department of Revenue's *Fall 2010 Revenue Sources Book* for FY 11 and FY 12; his March 15 production cost estimate adds another \$3.00 bbl. The increase to \$26.00 / bbl. represents a one-seventh increase in the per-barrel estimate calculation for production taxes (shown in Figure 2B, above, at Lines 7 and 10a) to provide cost relief for royalty barrels (one-eighth of North Slope production), which are not taxed. This increase is built into the ACES tax structure, despite the fact that royalty barrels are not subject to taxation and, under lease terms, do not receive the benefit of the cost deduction that the state has applied to production tax base since 2006.

²⁸ In April 1998, the press reported that according to U.S. Energy Information Administration data the total cost of producing oil dropped from \$14.61 in 1981 to \$4.12 per barrel (Dirk Beveridge [Associated Press], "Crude comes cut-rate; methods slash oil-finding costs," *Anchorage Daily News*, April 2, 1998, p. F-1).

²⁹ Alaska Department of Revenue, "The Cost Story," Oct. 21, 2007 (presentation to the Alaska State Legislature), slide 7.

sum, during the five years since Alaska enacted the cost-based PPT production tax, estimated production costs have increased 355% to 380% over the FY 2008 cost estimates on which the PPT formula was reckoned in 2006. While discussing field cost trends, it should be noted that there is often significant variation in regional costs.³⁰

With these principal taxation factors now clearly delineated, the stage is set for a more detailed look at TAPS tariff and low throughput issues.

IV. TAPS Economic and Low Throughput Issues

In the current campaign, TAPS comes to center stage as the fiscal and physically challenged conduit to market. TAPS has assumed this role for three reasons: (1) the pipeline's size (and ability to generate profits), (2) its unusual ownership overlap with the three major producers and (3) the fact that the continued operation of TAPS is necessary for the delivery of North Slope crude oil to market. To understand the convergence of these three characteristics and their significance, we begin this section with a brief review of TAPS economics.

IV.A. TAPS Economics

Figures 3 and 4 show clearly that TAPS tariffs (per-barrel shipping charges) are dwarfed by the trajectory of rising oil prices and the revenue that the North Slope delivers through TAPS, even at reduced production levels. One picture may be worth many words, but it is not necessarily the whole story. As in the case of establishing the distinction between marginal v. bottom-line effects of the state's fiscal regime, from a policy perspective it is important to understand where TAPS fits into the big picture. Returning to the three reasons above that propelled TAPS to prominence in this policy debate, the following questions underlie the economic consideration of TAPS issues: (1) Is TAPS merely another ostensibly small economic item whose significance lies in the power of multiplying per-barrel numbers by barrels delivered over the course of a year? (2) Is the pipeline's role as an income generator the only reason the TAPS owners spend so

³⁰ For additional background on rising production costs, see: *U.S. Energy Information Administration, Performance Profiles of Major Energy Producers, 2008*, December 2009, pp. 10-11 and 21 (Report No. DOE/EIA-0206[08]).

much time in state and federal tariff proceedings (challenged primarily by independent shippers), as well as administrative proceedings over property taxes (challenged primarily by municipalities)? (3) In view of the pipeline's vital role as a conduit to market, how did it come to pass that the owners now find the pipeline in danger of being shut down? A fourth question emerges from this line of inquiry: Does this understanding of TAPS issues help identify the significance of other overlooked issues?

In considering the possibility of TAPS shutdown, it is important to note that tariff regulatory provisions provide the pipeline owners with at least two significant financial benefits that provide incentive for the producer-owners to continue production and pipeline operations:

- TAPS operating income, guaranteed through rate-making proceedings, provides TAPS owners with annual profits that constitute an additional hedge against low oil prices; and
- The advanced collection of future dismantling funds (approximately \$1.5 billion since 1977) provides the TAPS owners with an accumulated cash balance today estimated at \$5.9 billion – an amount that is far in excess of estimated dismantling costs requirements. This pot of gold – an artifact of the 1985 TAPS tariff settlement agreement with the state – will continue to grow as long as TAPS continues to operate, postponing dismantling).³¹

Another TAPS policy issue that warrants consideration is the history of excessive TAPS tariff filings. This historical pattern – confirmed in both the 1985 TAPS tariff settlement agreement (which marked the resolution of an eight-year battle to lower tariffs) and the RCA and FERC decisions in this decade (finding that the 1985 settlement methodology

³¹ Author's estimate from FERC TAPS tariff proceeding files. For oblique footnote reference to CP's dismantling obligations (without mentioning or quantifying the cash for future outlays this tariff item has generated), see CP's 2010 10-K report at pp. 63 and 98. (For background information on this and other TAPS economic issues, see articles and links on this writer's web site at <http://www.finebergresearch.com/tapsecon.html> [FinebergResearch.com>The Oil Patch>Trans-Alaska Pipeline System: Economics]).

allowed tariffs that were, in fact, excessive) – suggests that the possibility that the TAPS owners handicap independent shippers by overcharging them.³²

A recent state court ruling at once highlights the importance of the unusual economic overlap between the major North Slope producers and the TAPS owners and calls into question the notion that TAPS might shut down. In a June 2010 decision following an extensively briefed, five-week trial in which municipalities on TAPS sought an increase in TAPS valuation for property tax payments, Superior Court Judge Gleason Sharon L. Gleason held that the replacement cost of TAPS – not the uncertain (and much lower) future TAPS income stream – is the correct basis for determining property tax valuation. Judge Gleason wrote:

The evidence at trial demonstrated that . . . the value of the remaining proven reserves on the North Slope was approximately \$350 billion. The value of those proven reserves cannot be realized without TAPS, as it constitutes the only viable means of transporting ANS product to market. Clearly, TAPS would be replaced to realize the value of those proven reserves if necessary. The Owners have asserted that TAPS' economic value derives primarily from its tariff income stream, and that TAPS was worth just \$850 million That proposed value for TAPS is less than 1/4th of one percent of the approximate \$350 billion value of the remaining proven reserves on the North Slope as of the lien date. This Court has concluded that the assessed value of TAPS is far greater³³

Judge Gleason's decision strikes a serious blow to the heart of the widely-held understanding that TAPS is correctly viewed as an independently operated profit center. Perhaps this, more than the bottom line effect, is the reason the TAPS owners invest so

³² Until Conoco traded its Milne Point field to BP in 1993 and left Alaska, that company was the only independent field operator on the North Slope (i.e., a field developer without an interest in TAPS). Later, President and CEO Archie Dunham would comment to an interviewer:

“It broke my heart to trade Milne Point, but we had to do it. All the value of that property was taken away from us in the pipeline tariffs. It was a valuable strategic lesson – just look at why the producers in the Caspian are so worried.”

– (Leslie Haines [interviewer], “Getting to the Future First,” *Hart's Oil & Gas Investor*, August 1996 [Vol. 16, No. 8], p. 41.)

Dunham and Conoco returned to the North Slope through merger with Phillips Petroleum in 2002 (two years after Phillips acquired ARCO's Alaska holdings, including its share of TAPS).

³³ Superior Court Judge Gleason Sharon L. Gleason, *Decision Following Trial de Novo: 2006 Assessed Valuation of the Trans Alaska Pipeline System (BP Pipelines [Alaska] Inc., et al., v. State of Alaska Department of Revenue, et al.*; Case No. 3AN-06-84446 C1 [Consolidated]), June 24, 2010, p. 169.

much time and energy in opposing such obscure and economically minor measures as property tax valuation methodology.

In any event, consideration of the overlap between production and TAPS economic arrangements suggest that the producer-owners of TAPS are not apt to walk away from North Slope and TAPS operations, despite rhetoric to the contrary. In sum, those who seek to make Alaska more competitive would be well advised to look more carefully at the economic interface between producer or shipper owners of the pipeline and independent producers.

IV.B. Operational Problems Associated with Low TAPS Throughput.

Turning now to the recently-celebrated operational problems associated with low TAPS throughput, this underlying question emerges: If low throughput indeed poses threat to continued TAPS operation, is a petroleum tax reduction in hopes of getting more oil into TAPS a direct and serious answer? This question involves consideration of two major TAPS programs: *Strategic Reconfiguration* (SR, the extensive pipeline makeover, begun in 2004, which features electrification and automation of the four pump stations that remain in service on TAPS), and *Cold Restart* (study of the capability to restart pipeline flow after an extended winter shutdown).

Strategic Reconfiguration. In 2003 and 2004, as Alyeska launched the SR project, the pipeline company emphasized that the new, variable-speed electric pumping units would replace the original jet-engine powered pumps, enhancing the pipeline capability to operate at higher and lower throughputs. Four of the original ten pumping units had been shut down between 1996 and 1998; as throughput continued to decline, two more of the original stations would be closed under SR along with the revamping of the four remaining pumping units.³⁴ According to the State Pipeline Coordinator's Office, "SR was intended to update TAPS for lower flow rates."³⁵ In a 2005 description of

³⁴ See: Alyeska Pipeline Service Company, *Pipeline Reconfiguration Project Overview: Pump Stations and Control Systems Upgrade – Project Completion by End of 2005*, March 2004, pp. 1-3 (12-page brochure; http://www.alyeska-pipe.com/Strategic%20Reconfiguration/PRO_12pg_Final_LR.pdf).

³⁵ State Pipeline Coordinator's Office, *Fiscal Year 2010 Annual Report* (Alaska Dept. of Natural Resources), p. 42.

the new pumping modules, Alyeska stated that the automated, electrified pump stations “will support throughputs between 350,000 and 1.14 million barrels per day.”³⁶ When the first new pumping system was placed in service in March 2007, Alyeska Vice President Mike Joynor told a reporter the new system would be able to go even lower, to 200,000 barrels per day.³⁷

When the SR project was formally announced in 2004, Alyeska anticipated the massive pipeline makeover would cost \$250 million and would be completed in 2005.³⁸ However, the SR project has experienced significant delays and has yet to be completed. By the start of 2011, three of the remaining pumping units were using their new systems, but reconfiguration of the fourth – Pump Station #1 at Prudhoe Bay – had been put off to 2013.³⁹ By 2007 SR costs had reportedly tripled.⁴⁰ Meanwhile, in a replay of the original TAPS tariff case, cost overruns are now the focus of a tariff battle between the state and the TAPS owners at the Regulatory Commission of Alaska (RCA) and Federal Energy Regulatory Commission (FERC).⁴¹

³⁶ Alyeska Pipeline Service Company, Pipeline Reconfiguration: Crude Oil Pump System,” July 19, 2005, p. 1 (http://www.alyeska-pipe.com/Strategic%20Reconfiguration/Crude_oil_pump_system.pdf).

³⁷ Alan Bailey, “TAPS switches to 21st century: Change over to new pump system marks new era for Alaska oil pipeline; throughput can be varied from 200,000 to 1.1 million bpd,” *Petroleum News*, Mar. 4, 2007, pp. 9-10.

This figure was repeated by the TAPS owners in a legal proceeding in May 2009. As recently as May 2009, when their representative in a legal proceeding stipulated to North Slope production through 2042, based on a minimum TAPS throughput of 200,000 bpd. (Testimony of Larry Mott on behalf of BP Pipelines (Alaska), Inc., May 21, 2009, *In the Matter of the Trans-Alaska Pipeline System, Oil & Gas Property Tax [AS 43.56], 2009 Assessment Year, (Appeal of Revenue Decision No. 09-56-02, CAH No. 09-SARB Tax before the State Assessment Review Board, State of Alaska, Vol. III), p. 782.*)

³⁸ Alyeska Pipeline Service Company, “\$250 Million TAPS Upgrade Approved: Alyeska starting biggest TAPS project since construction,” *Monthly News*, March 2004 (http://www.alyeska-pipe.com/Inthenews/Monthlynews/2004/March/mar2004_featurestory.asp); and *Pipeline Reconfiguration Project Overview*.

³⁹ Alan Bailey, “Trimming back: 60 jobs at Alyeska to go in 2010 as pipeline oil flow continues to decline; pump station 1 electrification to be delayed by one year,” *Petroleum News*, Nov. 15, 2009, p. 4.

⁴⁰ In 2007 the Alaska Department of Revenue reported that the estimated expenditure for SR was approximately \$750 million (*Revenue Sources Book*, Fall 2007, p. 44).

⁴¹ See: Regulatory Commission of Alaska Docket No. P-008-009 and Federal Energy Regulatory Commission Docket No. IS 09-348.

Cold Restart. TAPS was designed with the capability to resume pumping successfully after an extended winter shutdown at cold temperatures.⁴² However, as the pipeline's throughput declines, the oil travels more slowly and is therefore prone to cooling, resulting in increased precipitation of water and wax within the pipeline. Recent TAPS studies highlight a host of associated problems. In addition to creating potential for internal corrosion and a geotechnical hazard due to shrinking of the thaw-bulb surrounding buried pipe, reduced throughput adversely impacts TAPS restart capabilities. As the temperature of TAPS oil drops, ice blockage can damage pumps and strainers and other equipment or result in over-pressuring the line during re-start. Wax buildup poses a similar threat.⁴³

As originally designed, TAPS was capable of re-starting successfully after a 21-day shutdown at -40°F.⁴⁴ However, with fewer pump stations to reheat the oil in transit, the cooling of TAPS oil was identified as a problem shortly after the first round of pump station closures due to reduced throughput in 1996-97. The state-federal monitors of the Joint Pipeline Office required Alyeska to develop and test a plan for restarting the pipeline after extended shutdown periods during cold temperatures;⁴⁵ in 1998, pipeline

With regard to TAPS cost overruns, it should be noted that after TAPS began pumping in 1977, an investigating attorney's report to the Alaska Pipeline Commission (whose functions now lie with the Regulatory Commission of Alaska) claimed that at least \$1.5 billion in costs had been imprudently incurred during construction and therefore should not be recouped through tariff charges. The report noted difficulties obtaining documentary records as it put together its argument (Terry F. Lenzner, *The Management, Planning and Construction of the Trans-Alaska Pipeline System* [Report to the Alaska Pipeline Commission by the Commission's Special Counsel, Terry F. Lenzner], Aug. 1, 1977, Exec. Summary, p. 1 and Ch. XII-1 - XII-4). Eight years later, in the 1985 TAPS Settlement Agreement, the state gave up nearly all of the refunds sought. (See: "Prefiled testimony of R.,L. Bertschi," Alaska Public Utilities Commission, Docket No. P-86-2, Dec. 17, 1986. Bertschi estimated the state gave up an estimated \$3.6 billion in potential refunds when it settled the TAPS case.)

⁴² Alyeska Pipeline Service Co., *Summary Project Description of the Trans Alaska Pipeline System*, September 1975, p. 6.

⁴³ See, for example: Chuck Coulson (Chair, TAPS Owners Committee), *et al.*, *TAPS Low Throughput Issues*, October 1, 2008 (<http://taps-flow.com/TAPS%20Throughput%20Issues.ppt>).

⁴⁴ Alyeska Pipeline Service Co., *Design Basis Update* (DB-180, Ed. 3, Rev. 2), Dec. 31, 2000, p. 2-81.

⁴⁵ Robert Krenzelo, T&DR, "Cold Restart: TAPS Design Basis Compliance," Sept. 2, 1997 (Joint Pipeline Office Document #19970911-19). (Memorandum to Jerry Brossia [federal Authorized Officer, Bureau of Land Management] and Bill Britt [State Pipeline Coordinator], states in part: "Significant Issues: The Cold Restart Procedure is scheduled to be issued August 1998," p. 1.)

company officials acknowledged that “[w]hen Pump Stations 8 & 10 were shut down, since they were essential parts of the original Cold Restart Procedure, a new procedure was required.”⁴⁶

In the decade following the first round of pump station closures, time and again schedules were set for developing a viable Cold Restart plan; Alyeska routinely failed to meet its deadlines.⁴⁷ Meanwhile, without the heat from the closed interior pump stations, the oil temperature on the pipeline was dropping. By 2000, oil was still entering the pipeline at temperatures between 110° and 120° Fahrenheit, but in interior Alaska, within the pipeline the winter temperature reading of 90° had dropped to 66°. (By 2006, the interior pipeline temperature would drop to 45°.)⁴⁸

In 2002, Alyeska acknowledged that it could no longer meet the 21-day Cold Restart requirement; a draft version of the company’s Design Basis narrowed the window to 14 days. Three years later, in March 2005, Alyeska formally requested the change; in June 2005 JPO acknowledged Alyeska’s “current engineering judgment that there is now only

(This is the first of 16 items, listed in Appendix C. to demonstrate Alyeska’s chronic failure to meet deadlines for resolving the Low Flow and Cold Restart issues. The Joint Pipeline Office and State Pipeline Coordinator provided these documents in response to federal Freedom of Information Act and state Open Documents Act requests between 2007 and 2010.)

⁴⁶ Letter from Emery. L Monthei (Maintenance Reliability Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Cold Restart Procedure,” Aug. 13, 1998 (JPO Document # 19980821-8). [See Appendix C.]

⁴⁷ For example, when Alyeska failed to meet its deadline in time for the winter of 1999-2000, JPO formally ordered the pipeline company to provide a reliable schedule for the required cold restart procedure; again, Alyeska missed its deadline. By the start of the following winter, Alyeska had developed a “cool restart plan” that would not prevent the formation of the feared cold-weather plug but would help assure that the pipeline operators would not over-pressure a plugged line during a cold-weather restart. According to the text of the JPO’s 2001 Comprehensive Monitoring Program (CMP) report on TAPS operations, “until Alyeska has a final cold restart procedure and equipment in place to implement this plan, Alyeska is not in compliance with the TAPS Design Basis.” (Joint Pipeline Office, *A Look at the Operation of the Alyeska’ Pipeline Service Company’s Operation of the Trans-Alaska Pipeline System, 1999-2000* April 2001 [Comprehensive Monitoring Program] report], pp. 14-15.) At one point, JPO viewed Alyeska’s lack of cold restart capability as “the most significant issue” for TAPS operations,” but this statement of concern did not appear in the text operations report itself; it was found in the executive summary to the three-report CMP report package that contained the operations report, referenced above. [See Appendix C.]

⁴⁸ Alyeska Pipeline Service Company, *Facts*, various dates. (January 1999, pp. 86-87; May 2000, pp. 92-93; 1997, pp. 15-16.

a minimum of a 14 day shutdown window under arctic winter conditions as opposed to the 21 day ‘Original Cold Restart Plan’.” At that time, JPO asked Alyeska to “address the issues related to repair scenarios which cannot be performed in 14 days.”⁴⁹ According to Alyeska’s January 2011 “TAPS Low Flow Study Status” report, the pipeline company currently plans to “[d]etermine actions necessary to enable TAPS operations below 600,000 bpd down to approximately 300,000 bpd.”⁵⁰

Considering the peculiar Cold Restart and SR histories recounted here – and particularly the lack of progress in defining and implementing solutions – it can be questioned whether Alyeska’s vaguely worded low flow study plan reports should be given more credence than the earlier incorrect claims that SR itself was supposed to enable Alyeska to ship oil at lower throughputs.

The bottom line on TAPS Cold Restart issues is this: It is generally understood that the principal solution to low-throughput problems on TAPS is to heat the oil in the pipeline and keep it warm;⁵¹ the economic picture that has emerged from the background information presented in this narrative in Figures 1 through 4, suggests that the TAPS owners have both the financial resources and the economic incentive to apply this solution. Against this approach Alyeska President Tom Barrett strongly advocated doing whatever it takes to put more oil in the pipeline. But even though Alyeska’s new president stressed the economic outcome of higher per-barrel costs as throughput declined, he acknowledged that his primary concern was pipeline operations – not the economic drivers.

⁴⁹ Letter from Jerry Brossia (Authorized Officer, BLM/OIPM) and Frederick M. Thompson (Acting State Pipeline Coordinator) to Robert I. Shoaf (JPO Executive Liaison, Alyeska Pipeline Service Co.), June 29, 2005 (JPO Document #20050630-5). [See Appendix C.]

⁵⁰ Alyeska Pipeline Service Company, “TAPS Low Flow Study Status: Status of Study,” Jan. 31, 2011, (<http://www.alyeska-pipe.com/Inthenews/LowFlow/TAPS%20Low%20Flow%20Status-Public%20Release%2015Feb11.ppt#4>).

⁵¹ For a summary of the problems TAPS faces, see: Alyeska Pipeline Service Company, *Low Flow Impact Study, February 11, 2010, JPO Discussion* (briefing paper). For further discussion of heat application and low flow submitted to support municipality case for increased pipeline property taxes, see: Jerry L. Modisette, PhD, “TAPS Pipeline at Low Flows,” April 8, 2009 (11 pp.), and “Comments on Low Flow Heater Study” (rebuttal paper, 2 pp.).

A 2009 report on TAPS low flow issues by the TAPS owners listed a possible solution to the problem that came with a price tag that might be too high for the TAPS owners. The TAPS owners reported they had tabled the plan to spend \$15 billion to build a diluent crude upgrader plant on the North Slope to dissolve or mitigate wax in crude oil because it was too expensive.⁵²

IV.C. TAPS Issues: Concluding Questions.

The review of TAPS economics issues suggests two classes of concerns that might help explain the lack of interest in North Slope development that causes worried Alaskans to advocate tax cuts in hopes of inducing more exploration efforts.

With regard to tariff issues in general:

- Could the history of TAPS owner tariff overcharges deter potential investors (who might have to pay those charges out of pocket) from Arctic development?

With regard to Cold Restart:

- Could potential investors be spooked by Alyeska's failure to deal with low throughput problems in a timely and effective manner?

Putting these two issues together:

- When cost overruns that plague the original pipeline construction and the recent SR project are a matter of record, does the possibility of cost overruns on a Cold Restart fix tend to scare off potential investors?
- If an investment on the order of magnitude of the tabled \$15 billion diluent plan might be required to resolve low-flow problems, would the subsequent TAPS tariff increase to pay for this project inhibit future investors, countering the increased exploration and development activity the proponents of HB 110 are hoping that tax reduction at state expense might (or might not) induce?

⁵² TAPS Owners, "Trans-Alaska Pipeline System Low Flow Plan Summary: A Report on Low Flow Issues Through 2030," June 3, 2009, slide 17 [mis-numbered slide 1].

V. Audits: The Missing Link

As the state switched to a cost-based production tax in 2006, the necessity of improving auditing processes to assess the cost data necessary to assure that tax payments reflected actual expenditures was evident. In August 2007, when Governor Sarah Palin announced the special session to reconsider the new production tax enacted one year earlier, her press release noted that “[c]ompanies are reporting far greater costs than were predicted when PPT was passed the preceding year.”⁵³ At the outset of the 2007 special session during which ACES was enacted, the administration assured legislators that “ACES improves audit function.”⁵⁴ In subsequent years, the importance of audits was underscored by the rapidly increasing field costs noted in Section II (Figure 2A and 2B) and Section III (Figure 4).

Audits were not up to the task of. Responding to the Division of Legislative Audit's Statewide Single Audit's sharp criticism of the Department of Revenue's petroleum tax audit procedures and performance on March 18 of this year, Revenue Department Commissioner Bryan Butcher acknowledged that state's tax audit capabilities have been plagued by problems that include:

- “Staff turnover. . .
- “the inability to recruit senior level auditors at current pay levels, despite intensive recruitment efforts. . . .
- “less experienced auditors . . . working on major audits;
- “supervisors. . . spend time conducting complex audits, instead of using that time to supervise and develop audit manuals, processes and procedures; and
- “lack of automated tax processing systems to manage and share information.”⁵⁵

⁵³ Office of the Governor, “Special Session to Revisit Oil Taxes” (Press Release 07-173), August 3, 2007.

⁵⁴ Alaska Department of Revenue, “The Cost Story,” October 21, 2007 (slide presentation), slides 9 and 13.

In 2006, when I asked Revenue Department representatives who were advocating a cost-based tax about the possibility of audit problems, agency personnel responded that cost information gathered for income tax collection would suffice, and that litigation over cost issues was unlikely.

⁵⁵ Commissioner Bryan Butcher (Department of Revenue), letter to Legislative Auditor Pat Davidson (Division of Legislative Audit), March 18, 2011, pp. 2-3.

In view of the revenue amounts at issue, when lack of a computer system to handle industry documents has seriously hampered the audit process since the cost-based production tax was put in place, it is hard to believe that only now are steps being taken to obtain funding for a computerized audit data system.⁵⁶

In implementing a cost-based production tax, audit reviews were particularly important for two reasons: to establish a baseline for tracking costs, and to ensure the validity of reported cost increases. However, in hearings on HB 110, Revenue Department testimony indicated that the audit process has been narrowly focused on determining that expenditures were recorded so that capital credits could be issued – a far more limited purpose and much less definitive reckoning than an audit to calculate and verify what the industry actually spent and exactly how it used those reported expenditure entries.⁵⁷

Although the extraordinary increase in North Slope production cost increases warrant careful scrutiny, hearing testimony to date has not provided clear understanding of the basis for calculating this important tax element, or the verification of the various estimates that have been presented.

⁵⁶ For a summary account of this accounting problem, see: Dermot Cole, "Senate seeks \$34.7 million to replace antiquated Alaska oil tax audit system; most recent audit from 2006," Fairbanks Daily News-Miner, April 2, 2011 (http://newsminer.com/pages/full_story/push?blog-entry-Senate+seeks+-34-7+million+to+replace+antiquated+Alaska+oil+tax+audit+system-+most+recent+audit+from+2006%20&id=12605080&instance=blogs_editors_desk).

⁵⁷ See presentations of Department of Revenue Audit Master Lennie Dees, accompanied by Deputy Commissioner Bruce Tangeman. Senate Finance, Feb. 10, 2011 and House Finance, Feb. 10 and March 17, 2011.

In a letter from Deputy Revenue Commissioner Tangeman ("SUBJECT: Response to Questions Asked of the Department of Revenue at the January 25, 2011 forecast overview in the Senate Finance Committee," Feb. 8, 2011) to Senators Lyman Hoffman and Bert Stedman [Co-Chairs, Senate Finance Committee], the department noted some personnel recruiting difficulties (pp. 1-2) and stated that the Production Tax Audit section receives *some* specific information about historical capital spending" (emphasis added, p. 4).

In the graphic presentation Feb. 10 ("Production Tax Credits"), 33 of 34 slides dealt with capital credits; only the final slide displayed the increasing capital expenditures for 2006 through 2012, against which those credits were charged.

The increasing leverage of increased production costs to reduce the state's progressive production tax base (see Figure 2B, Lines 10a through 10f) has been identified as a factor that is liable to set in motion aggressive industry accounting practices that include gold-plating – loosely defined as unnecessary expenditure or the reporting of excessive costs.⁵⁸ In this regard, it should be noted that the provision of the existing ACES bill that enables the industry to deduct eight dollars from the tax base for every seven dollars reported as spent (an accounting artifact designed to extend to producers the benefit of cost deductions to royalty barrels, even though Alaska royalty contracts, as a general rule, allow deductions only for transportation – not for production costs)⁵⁹ increases the industry's reward for gold-plating its tax returns.

VI. Questionable Accounting Practices and the Importance of Audits

By no means are field costs the only production tax calculating input that affects the petroleum revenue payments. A major element in assuring the state receives fair value, for example, is accurate reporting of the value of each barrel of oil. The state's petroleum litigation history clearly demonstrates the importance of validating the revenue calculation starting point – particularly when transfer pricing from one arm of a company to another is involved.

In a 2007 study of multinational oil corporations and resource development, noted economist Joseph Stiglitz portrayed Alaska as the poster-child of corporate cheating. Stiglitz described his first-hand experience with Alaska – in royalty litigation during the 1980's – as follows:

“The prospects of cheating are very real and great, and can arise at every stage of the transaction. The government may get less for the lease than it should – there may even be attempts to restrict competition in bidding. Whatever the contract that has been signed, corporations are tempted to cheat – to pay less than they are supposed to – because the amount of money that can sometimes be made by doing so is so large. The occasions to cheat arise not just in developing countries. In the 1980s I worked on a case involving cheating by the major oil companies in Alaska. This oil-rich state had a mineral lease requiring the oil companies

⁵⁸ See: Roger Marks, “Evaluation of ACES with HB 110 Proposal,” March 15, 2010, on-line slide #24, (presentation to the House Finance Committee).

⁵⁹ See footnote 27, above.

to pay at 12.5 percent of the gross receipts, less the cost of transporting the oil out from the far-flung site at Prudhoe Bay on the Arctic Circle. By overestimating their costs by just a few pennies per gallon (and multiplying those pennies by hundreds of millions of gallons) the oil companies would increase their profits enormously. They could not resist the temptation.

They also found other ways to cheat, such as selling their oil to their own subsidiaries, recording a lower than fair market value (see chapter 4); or using other subsidiaries to ship their oil out and then reporting fictionally high shipping cost. Each piece of the cheating was hard to detect, and government prosecutors had to analyze thousands of transactions- – at a cost of tens of millions of dollars. In the end, there was no doubt that cheating had occurred – and on a massive scale. There followed a series of settlements involving a whose who of global companies – including what are now BP, ExxonMobil and ConocoPhillips – for an amount in excess of 6 billion dollars.⁶⁰

The \$6-billion estimate by Stiglitz was conservatively cast; state records compiled and reported on by this writer in 2003 showed that the Alaska Dept. of Law reported \$6.8 billion in oil and gas settlement payments for underpayments on taxes and royalties through 2001.⁶¹ Since that time, the Constitutional Budget Reserve Fund reports taking in another \$1.5 billion in oil and gas settlements, bringing the total revenue gained through petroleum litigation since Prudhoe Bay entered production to \$8.3 billion.⁶²

Is trust or verification the wiser policy? It is difficult to answer this question because the critical facts about these settlements remain shielded behind the veils of taxpayer

⁶⁰ Joseph E. Stiglitz, "What Is the Role of the State?" Macartan Humphreys, Jeffrey D. Sachs and Joseph E. Stiglitz (eds.), *Escaping the Resource Curse* (Columbia University Press, 2007), pp. 24-25 (footnotes omitted).

⁶¹ See: Richard A. Fineberg, "[Securing the Take: Petroleum Litigation in Alaska](#)," in *Caspian Oil Windfalls: Who Will Benefit?* [New York: Open Society Institute, 2003], pp. 53-69 [Chapter 3]. (Stiglitz cited my 2003 compilation as the source for his statement that the state was short-changed and forced to litigate to recoup "in excess of 6 billion dollars.")

Although I never met Prof. Stiglitz, while serving in the governor's office between 1987 and 1989 I worked on the royalty case that he discusses here. During this period, in addition to serving with the governor's policy review team, I spent time with the state's contractual staff team tallying data on oil transactions; this experience enabled me to give first-hand information to the governor's policy review team. Given this common background, I can confirm the accuracy of the Stiglitz observations.

⁶² Alaska Department of Revenue, *Fall 2010 Revenue Sources Book*, p. 90. (Under Article IX, Sec. 17 of the Alaska State Constitution, the state deposits all money received as a result of administrative proceedings or litigation on mineral lease payments or taxes on mineral income into this fund.)

confidentiality and commercial propriety. However, the softness surrounding important numbers that have swirled around the current petroleum tax discussion suggest to me that at this time we do not have a firm grip on this issue. The following empirical indicators tip the scales toward verification:

- The Department of Law has put in a budget request for \$5 million for the coming fiscal year for outside counsel to assist with oil and gas litigation.⁶³
- In my experience, litigation has typically yielded a pay-out on state investment conservatively estimated at 10:1.
- In 2006 and 2007, veteran state oil and gas personnel assured me that the relatively large sums of money at issue in revenue disputes were a thing of the past – an historical artifact that reflected the fact that nation’s largest oil field came on-line in the midst of the two significant price spikes of the 1970’s, confronting both the industry and the state with a steep learning curve. Balanced against this sanguine historical interpretation is the fact that \$1.3 billion of the most recent \$1.5 billion in litigation revenue has been collected in the last four years.⁶⁴

VII. ConocoPhillips Estimates of the Future Profitability of Its ANS Holdings

While recent data on Alaska petroleum operations demonstrate the continued profitability of the North Slope and TAPS (see, for example, Figures 1 and 2, above), past performance is no guarantee of future outcomes. Because development policy is all about the future, this section undertakes analysis of estimates of future profitability of Alaskan oil reported by ConocoPhillips (CP). Analysis of this body of information requires careful navigation through concepts designed to deal with the uncertainties of the future and the complexities of dealing with the time value of money.

As part of the break-down by regions in its 10-K report, CP shows the cumulative total of the annual amounts the company anticipates that it will retain from Alaska production revenues in excess of the amounts necessary to cover all future expenses; company

⁶³ Alaska Dept. of Law, “Oil and Gas Litigation (Non-Gasline),” Reference No. 51784, Feb. 16, 2011 [FY 2012 Governor Amended Capital Project Summary], pp. 1-2.

⁶⁴ *Fall 2010 Revenue Sources Book*, p. 90.

future expenditure estimates include a reasonable profit allowance on future company operations. The bottom line in this bloc of data – the discounted future net cash flow – represents the present value of the estimated annual amounts by which CP's future petroleum revenue pay-off will exceed cash outlays. To assure consistency in its reporting, the SEC requires these figures to be calculated at a 10% discount rate. This filing therefore provides a standardized basis for inter-regional and inter-company comparisons.⁶⁵

In fulfillment of SEC requirements, CP also reports capitalized (depreciated) costs, which represents the amount (net of depreciation) that CP has spent on the regional reserve assets that will be producing the discounted future net cash flow.⁶⁶ For each reported region, the ratio between the discounted future net cash flow and the capitalized costs provides a standardized basis for comparison. Although this *pro forma* company look at its future prospects does not constitute a forecast, these standardized data enable meaningful inter-regional comparisons.⁶⁷

The following three charts use data from this standardized methodology, as reported over the last five years, to make comparisons, from several perspectives, between CP's prospects for its investment and anticipated returns on future production in Alaska and

⁶⁵ ConocoPhillips, "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities," *10-K Annual report pursuant to section 13 and 15(d)*, Feb. 23, 2011 (for Calendar Year 2010), pp. 161-163 (excerpted pages in Appendix D at back of this report).

⁶⁶ "Capitalized Costs," *10-K Annual report pursuant to section 13 and 15(d)*, Feb. 23, 2011 (for Calendar Year 2010), p. 160 (excerpted pages in Appendix D at back of this report).

⁶⁷ For brief discussion of CP's reporting methodology, see: See: ConocoPhillips, "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities" (10-K Annual report for File Period ending 12/31/2010), Feb. 23, 2011, p. 161.

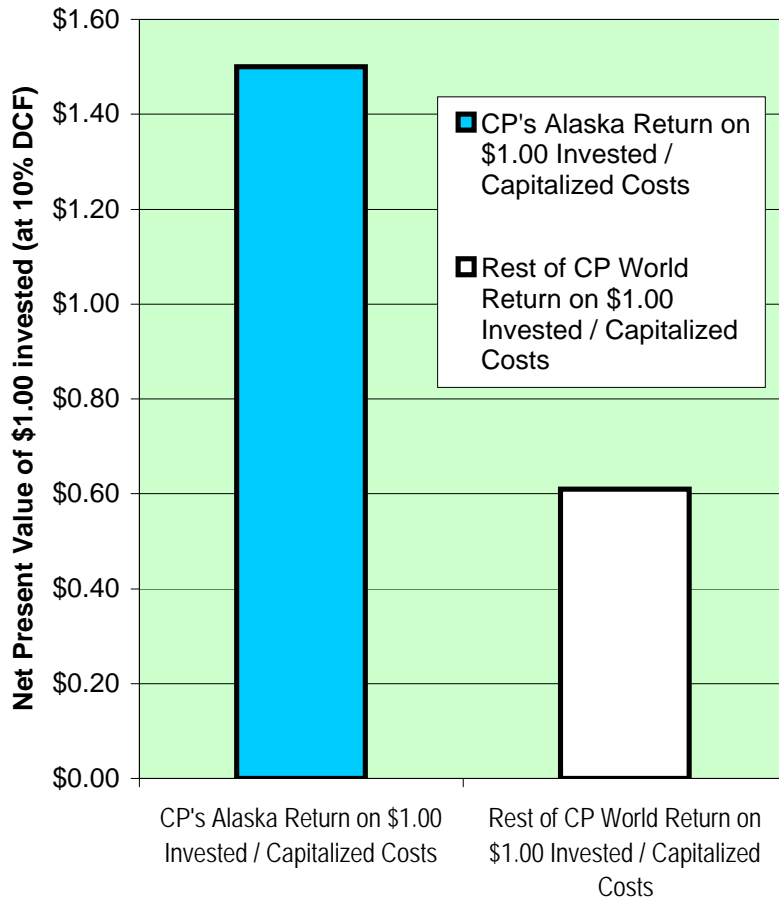
The NPV of the discounted cash flow resulting from these calculations does not constitute a forecast for two principal reasons: First, in forecasts, businesses typically use their own hurdle rate of return (the internal rate of return that matches what they anticipate their other investments can earn); this discount rate is usually higher than the SEC's 10% requirement. Secondly, SEC requires that companies conduct their analysis using a fixed oil price, based on the actual oil price at the end of the reporting year; forecasters typically posit oil prices that may fluctuate, rise and or fall, reflecting their beliefs about future economic conditions. While this mode of analysis is not an economic forecast, the required data provide a standardized basis for comparisons that avoids (or greatly reduces the distortions and subjectivity inherent in forecasting.

the company's investments elsewhere.⁶⁸ In these charts, each vertical bar represents the ratio – for Alaska or another region (or group of regions) – between (1) CP's anticipated discounted future net cash flows from investment in the development of petroleum reserves in question and (2) the capitalized cost to acquire those reserves. In concept, these bars represent the forward-looking counterpart of CP's historical earnings data for 2006 through 2010 shown in Figure 1.

As shown in Figure 5, in 2010 CP estimated that its earnings per dollar paid for Alaska's proved reserves would more than double the net present value of the company's average returns on its other producing oil assets. In other words, in 2010 CP's standardized data indicated that the company's Alaska oil reserves would produce more than twice the corporate profit per dollar under the ACES tax regime than the company would earn from the average dollar invested in other parts of the world.

⁶⁸ The regional and company-wide discounted future net cash flows and capitalized cost estimates employed to build these charts are displayed in Appendix D at the back of this report.

ConocoPhillips Estimated Future Alaska Oil and Gas Profits vs. Other CP Oil and Gas Investment at 10% Net Present Value*
(Based on 2010 data reported to SEC, @ \$89.75/bbl. [2010 \$])



ConocoPhillips (CP) annually estimates the net present value of future cash flows from proved oil and gas reserves in various regions, discounted at 10%, with oil prices and tax levels at the end of the reporting year held constant (reporting required by the Securities & Exchange Commission). The CP upstream* relative profits estimate represents the ratio of the discounted, tax-paid net revenue CP anticipates it will receive annually from production of proved reserves, by region, and what CP has spent to obtain and develop those reserves. In 2010, CP estimated Alaska's future proved reserves would outperform each of its other regions, more than doubling the average of the rest of its producing assets, as shown above.

*** This regional comparison excludes profits from the Trans-Alaska Pipeline and marine transportation.**

Sources : ConocoPhillips, 2010 10-K Report (filed Feb. 23, 2011), pp. 161-163; oil price shown here is ANS December 2010 average, estimated by Research Associates from Alaska Dept. of Revenue data.

Using the same methodology, Figure 6 reports CP's estimates of Alaska's future performance for each year since 2006, compared to the rest-of-company average. As in Figure 5, for each year the blue bar representing the NPV of each dollar invested to date in Alaska's reserves indicates superior anticipated earnings from Alaska. Between 2008 and 2010, the gap has widened between the increasing anticipated future earnings per dollar from CP's Alaska investment and the company's significantly lower anticipated earnings from the rest of the world. These data therefore suggest that under ACES regime the relative attractiveness of Alaska's investment prospects has increased, despite the ACES tax bite that increases with rising oil prices.

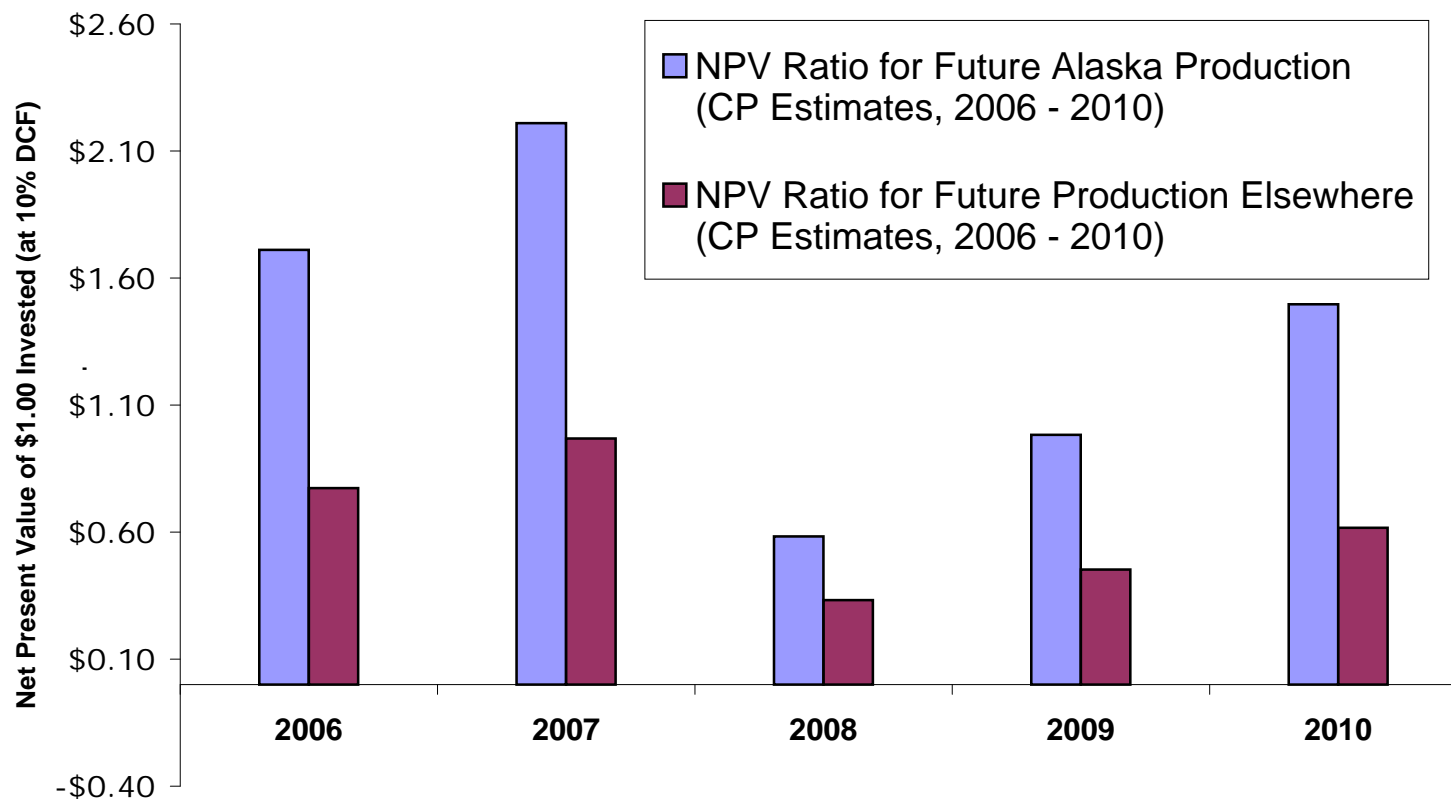
It should also be noted that between 2008 and 2010 the prior year end-of-year oil price that serves as a key variable in calculating the discounted future net cash flows varied widely, testing ACES performance at both low prices (approximately \$40.00 / bbl. market price in 2008) and high (\$89.75 / bbl. in 2010).⁶⁹ As shown in Figure 6, Alaska passed the test: CP estimated that it would receive a higher return per dollar invested in Alaska than in the rest of its properties under both conditions.

⁶⁹ For monthly average Alaska oil prices, see Appendix B at the back of this report.

Figure 6. ConocoPhillips Future Profitability Estimates (Chart 2 of 3)

CP Estimates of NPV Ratios for Future Production, Alaska and Elsewhere

(NPV of Future Production at 10% Discount)/(Capitalized Costs)



ConocoPhillips annual estimates of future returns from Alaska reserves (left-hand bar) consistently outweigh returns from the company's reserves elsewhere (right-hand bar). Each bar above shows CP's estimated net present value of discounted future cash flows from proved reserves, per dollar invested to date, after all future costs (including a 10% annual rate of return) are paid.

Sources: Data from CP Form 10-K (calendar year 2010, pp. 160-162; 2009, pp. A-135 – A-137; and 2008, pp. 163, 165); and Annual Financial Report (2006, pp. 109-110). (See Appendices C and D for ratio data.)

Figure 7 compares CP's projection of its Alaska earnings in 2009 and 2010 to the other regions in the world in which CP operates. For the last two years, Alaska under ACES came out on top in every CP regional comparison but one: Russia in 2009, where CP's high hopes for its minority investment in the oil and gas company Lukoil temporarily boosted a much lower 2008 NPV. Those hopes quickly collapsed, however, and in 2010 as CP sold its interests in Lukoil back to the company.⁷⁰ While CP avoided getting scalped, the volume of its investment was decimated.⁷¹

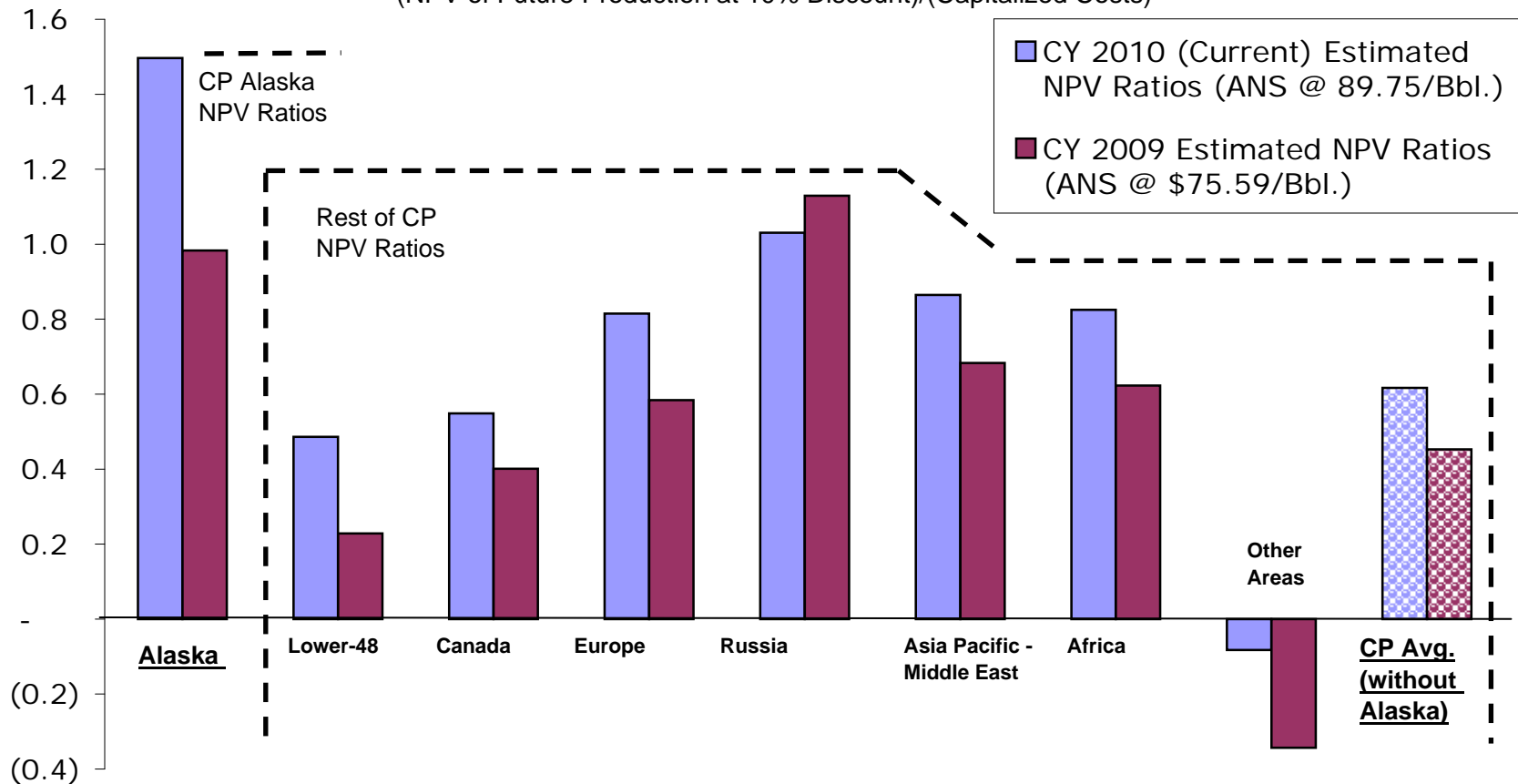
⁷⁰ Jacob Gronholt-Pedersen, "Russia Chapter Ends for ConocoPhillips," Wall Street Journal, July 28, 2010 (<http://online.wsj.com/article/SB10001424052748703940904575395291612519442.html>).

⁷¹ The gross reduction in the anticipated investment and earnings in CP's Russian province in 2010, can be seen in the CP 2010 10-K report extract, pp. 160-163. These pages can be found at Appendix D in the back of this report.

Figure 7. ConocoPhillips Future Profitability Estimates (3 of 3)

2009 and 2010 Estimated NPV Ratios: Alaska v. Other CP Regions

(NPV of Future Production at 10% Discount)/(Capitalized Costs)



ConocoPhillips CY 2010 (left-hand bars) and 2009 (right-hand bars) are estimates of future net present value of investments by region. Each bar represents the ratio of (1) net revenue surplus to the amount necessary to earn a 10% rate of return on estimated future expenses in each region over (2) capital investments to date in that region.

Sources: NPV ratio data from Conoco Phillips Form 10-K for Fiscal Year ending Dec. 31, 2010 (Feb. 23, 2011), pp. 160 – 162; Alaska North Slope year-end crude oil prices for 2009 and 2010 shown in real [2011] dollars, estimated from Alaska Dept. of Revenue data.

In sum, the CP data distilled and displayed in these three charts constitute a strong, forward-looking challenge to the notion that the progressive production tax enacted by the legislature during intensive special sessions in 2006 and 2007 has chilled investment in Alaska. The fact that CP anticipates that its proved reserves in Alaska will deliver NPV results that far exceed returns from other regions in the CP portfolio lends strong support to the conclusion that CP will not walk away from its Alaska holdings.

VIII. Conclusions

Here are key findings of this report that warrant further attention during consideration of Alaska's petroleum revenue system:

In compliance with federal Securities and Exchange Commission requirements, CP publishes data annually comparing the finances of its Alaska operations to those of other regions of the world in which it operates. CP, Alaska's largest oil producer, is the only major North Slope operator that reports this information. Review of CP's current and estimated future results, presented in four charts in this report, show that CP anticipates that Alaska's steady performance under the ACES tax regime is likely to continue in the future, bringing in significantly better future returns than the anticipated company-wide average. *(These data are summarized in report Figures 1 [current results] and 5 through 7 [net present value of anticipated future returns]).*

- Although ConocoPhillips claims investment in future production of proved Alaska reserves requires additional tax breaks, these annually filed data show that CP estimates of its future returns on proved Alaska oil reserves have consistently exceeded the company's estimate of its anticipated returns on proved reserves elsewhere in the world in every year since Alaska instituted its cost-based petroleum production tax in 2006. *(See Figure 6.)*
- While advocates of tax reduction claim that Alaska is no longer competitive because the progressive ACES tax regime takes too large a share of revenue at high oil prices, when oil prices rising to averaging approximately \$89.75 in 2010, CP's annual filing showed that the company's anticipated returns on proved Alaska reserves at that price will exceed the company's anticipated returns from every other region in the world. *(See Figure 7.)*

The presidents of CP Alaska and the Alyeska Pipeline Service Company argue that immediate tax reduction is necessary to induce increased North Slope production because TAPS cannot handle declining throughput effectively. This argument stands in marked contrast to the claims, made since 2004, when Alyeska instituted the massive pipeline makeover known as Strategic Reconfiguration, that the reconfigured pipeline could handle low flows. *(Section IV.)*

- Review of historical records shows that Alyeska's decision to close pump stations, dating back to 1996, exacerbated the TAPS low flow problems, and that subsequently Alyeska frequently failed to meet its deadlines for addressing these problems. (See Section IV.B and Appendix C.)

In 2006 and 2007, the state instituted measures to share downside risks in response to the industry's desire to reduce investor exposure to volatile oil prices (pp. 3-4).

- In exchange, when rising oil prices create windfall profits for the industry, the progressivity factor the Legislature put into place with ACES in 2007 enables the state take in a larger portion of that windfall revenue, while the industry still continues to profit (Figure 2A.).

While focusing on shares of the marginal dollar gained as oil prices rise, tax cut proponents fail to recognize that industry's smaller share of gains from a price increase is actually a windfall return without additional investment. Moreover, the industry's smaller share per barrel may yield significant financial gains.

- For example, I estimate that the industry's share of a \$10.00 / bbl. price increase from \$80.00 to \$90.00 / bbl., annualized at 650,000 bpd would add up to somewhere between \$386 million \$467 million per year. (See Figures 2A and 2B.)

Apart from the continued profitability of North Slope operations under ACES, several facts presented in this report suggest that the major TAPS owners, who also control approximately 95% of North Slope production, are not likely to walk away from TAPS. (See Section IV.A., pp. 20-23.)

- In addition to the continued profitability of North Slope production, the TAPS owners receive a guaranteed profit on TAPS shipments at all oil prices and are holding the advanced collection of funds for the future dismantling of TAPS (p. 21).
- A recent state court ruling at once highlights the importance of the unusual economic overlap between the major North Slope producers and the TAPS owners and calls into question the notion that TAPS might shut down (p. 22).
- In view of the historical pattern of excessive TAPS overcharges, the possibility that the TAPS ownership handicap independent shippers also warrants attention. In this regard, note the 1996 statement of then-Conoco CEO Archie Dunham, that Conoco left the North Slope in 1993 because "[a]ll the value of that property was taken away from us in the pipeline tariffs" (pp. 21-22).

The administration has not presented hard data to support its contention that additional tax breaks are necessary to induce development at this time. One of the reasons the current tax dialogue is lacking in substantive information is that the state has failed to implement the audit program that was supposed to enable the state to track production costs, which were not calculated under the old production tax regime but are central to the new system. (See *Section V.*)

- One of the reasons the ACES special session was called in 2007 was the unexpected increase in North Slope production costs that reduced tax revenue from the new, cost-based production tax, implemented in 2006. To deal with this situation, ACES was supposed to provide improved auditing. However, field costs have continued to rise while the audit system has failed to establish the basis for calculating and verifying production costs, or to provide clear understanding of how the industry has used capital credits awarded under the new system. (See *Section V.*)

This fact underscores the importance of the state's inability to get its petroleum tax auditing act together: In the 33.5 years since Prudhoe Bay entered production, the state has had to challenge the industry to obtain a reported \$8.3 billion in oil and gas settlements for underpayment on taxes and royalties. In a 2007 book on government relations with the oil industry, Joseph Stiglitz, a noted economist who worked on one Alaska case, characterizes the major North Slope producers as cheaters. (See *Section VI, pp. 31-32.*)

- As oil prices have increased during the last decade, so has the rate of contested or litigated collections. Of the \$1.5 billion deposited into the Constitutional Budget Reserve Fund since 2001, \$1.3 billion has been received in the last four years. (See *Section VI., pp. 32-33.*)

It is the burden of this report is that the information presented for legislative consideration in hearings to date has not provided sufficient basis for making and supporting informed policy decisions.

Appendices

- A. Extracts from ConocoPhillips 10-K Reports (Current Operations). . . . A -1
- B. Alaska North Slope Crude Oil Price History (1988 – 2011). A – 7
- C. Alyeska Pipeline Service Company Cold Restart History,
1997-2007: Extracts from Selected Documents A – 9
- D.. Extracts from ConocoPhillips 10-K Reports (Future Profitability) . . . A - 13

Appendix A

Extracts from ConocoPhillips 10-K Reports (Current Operations). A -1

CONOCOPHILLIPS (COP)

10-K

Annual report pursuant to section 13 and 15(d)

Filed on 02/23/2011

Filed Period 12/31/2010



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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2010	2009*	2008*	2007*	2006*
Sales and other operating revenues	\$ 189,441	149,341	240,842	187,437	183,650
Net income (loss)	11,417	4,492	(16,279)	11,545	15,410
Net income (loss) attributable to ConocoPhillips	11,358	4,414	(16,349)	11,458	15,334
Per common share					
Basic	7.68	2.96	(10.73)	7.06	9.67
Diluted	7.62	2.94	(10.73)	6.96	9.53
Total assets	156,314	152,138	142,865	177,094	164,557
Long-term debt	22,656	26,925	27,085	20,289	23,091
Joint venture acquisition obligation—long-term	4,314	5,009	5,669	6,294	-
Cash dividends declared per common share	2.15	1.91	1.88	1.64	1.44

*Recast to reflect a change in accounting principle. See Note 2—Changes in Accounting Principles, for more information.

Many factors can impact the comparability of this information, such as:

- The financial data for 2010 includes the impact of \$5,803 million before-tax (\$4,583 million after-tax) related to gains on asset dispositions and LUKOIL share sales.
- The financial data for 2008 includes the impact of impairments related to goodwill and to our LUKOIL investment that together amount to \$32,939 million before- and after-tax.
- The financial data for 2007 includes the impact of a \$4,588 million before-tax (\$4,512 million after-tax) impairment related to the expropriation of our oil interests in Venezuela.

See Management's Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

Segment Results

E&P

	2010	2009	2008
	Millions of Dollars		
Net Income (Loss) Attributable to ConocoPhillips			
Alaska	\$ 1,735	1,540	2,315
Lower 48	1,033	(37)	2,673
United States	2,768	1,503	4,988
International	6,430	2,101	6,976
Goodwill impairment	-	-	(25,443)
	\$ 9,198	3,604	(13,479)

	Dollars Per Unit		
Average Sales Prices			
Crude oil and natural gas liquids (per barrel)			
United States	\$ 69.73	53.21	89.38
International	74.95	57.40	89.32
Total consolidated operations	72.63	55.47	89.35
Equity affiliates	74.81	58.23	71.15
Total E&P	72.77	55.63	88.91
Synthetic oil (per barrel)			
International	77.56	62.01	103.31
Bitumen (per barrel)			
International	51.10	39.67	46.85
Equity affiliates	53.43	45.69	58.54
Total E&P	53.06	44.84	56.72
Natural gas (per thousand cubic feet)*			
United States	4.27	3.50	7.60
International	5.60	5.06	8.65
Total consolidated operations	5.07	4.40	8.20
Equity affiliates	2.79	2.35	2.04
Total E&P	4.98	4.37	8.18

*Prior periods reclassified to conform to current year presentation which includes intrasegment transfer pricing.

Average Production Costs Per Barrel of Oil Equivalent			
United States	\$ 8.30	7.73	8.34
International	7.96	7.72	8.03
Total consolidated operations	8.10	7.73	8.17
Equity affiliates	8.11	7.68	13.36
Total E&P	8.10	7.72	8.33

	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical; and lease rentals	\$ 678	576	639
Leasehold impairment	241	247	273
Dry holes	236	359	425
	\$ 1,155	1,182	1,337

2008

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K**

(Mark One)

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

Commission file number 001-32395

ConocoPhillips

[Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934]

[Accessed 110223 at

http://investing.businessweek.com/businessweek/research/stocks/financials/drawFiling.asp?docKey=136-000136231009002769-2LPN3T5OVV7ES551J09VR27UKV&docFormat=HTM&formType=10-K]

Segment Results – E&P

	2008	2007	2006
	Millions of Dollars		
Net Income (Loss)			
Alaska	\$ 2,315	2,255	2,347
Lower 48	2,673	1,993	2,001
United States	4,988	4,248	4,348
International	6,976	367	5,500
Goodwill impairment	(25,443)	—	—
	<u>\$ (13,479)</u>	<u>4,615</u>	<u>9,848</u>

	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	\$ 97.47	68.00	61.09
International	93.30	70.79	63.38
Total consolidated	95.15	69.47	62.39
Equity affiliates*	63.89	45.31	46.01
Worldwide E&P	93.12	67.11	60.37
Natural gas (per thousand cubic feet)			
United States	7.67	5.98	6.11
International	8.76	6.51	6.27
Total consolidated	8.28	6.26	6.20
Equity affiliates*	2.04	.30	.30
Worldwide E&P	8.27	6.26	6.19
Natural gas liquids (per barrel)			
United States	55.63	46.00	40.35
International	59.70	48.80	42.89
Total consolidated	57.43	47.13	41.50
Worldwide E&P	57.43	47.13	41.50

Average Production Costs Per Barrel of Oil Equivalent**			
United States	\$ 8.34	6.52	5.43
International	8.08	7.68	5.65
Total consolidated	8.20	7.13	5.55
Equity affiliates*	13.51	8.92	5.83
Worldwide E&P	8.37	7.21	5.57

* Excludes our equity share of LUKOIL, which is reported in the LUKOIL Investment segment.

** For information on taxes other than income taxes per barrel of oil equivalent, see the "Statistics" section of the supplemental Oil and Gas Operations disclosure.

	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical; and lease rentals	\$ 639	544	483
Leasehold impairment	273	254	157
Dry holes	425	209	194
	<u>\$ 1,337</u>	<u>1,007</u>	<u>834</u>

Appendix B

Alaska North Slope Crude Oil Price History (1988 – 2011) A - 7

ANS West Coast Price

Year	Price (Nominal \$ per barrel)												Calendar Year Avg.		GDP Deflator
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	(Nominal)	(Real)	(Chained Price Index)
1988	14.23	14.03	13.79	15.29	14.86	14.14	13.70	13.63	12.58	11.34	11.36	13.23	\$13.52	\$22.47	0.6694
1989	15.11	15.99	17.25	19.37	17.64	17.00	16.78	16.04	16.62	17.27	17.49	19.07	\$17.14	\$27.42	0.6954
1990	20.00	19.30	17.91	14.82	14.38	13.20	15.55	25.99	32.16	31.53	28.79	24.02	\$21.47	\$33.14	0.7210
1991	20.57	15.74	17.02	17.56	16.67	16.36	17.25	17.18	17.37	18.47	17.57	14.83	\$17.22	\$25.60	0.7483
1992	14.92	15.30	15.50	16.96	18.03	20.20	19.40	17.97	18.46	18.71	17.46	16.33	\$17.44	\$25.27	0.7678
1993	15.62	16.78	17.35	18.17	17.47	16.02	14.84	15.42	14.98	15.39	13.07	10.29	\$15.45	\$21.91	0.7848
1994	11.66	12.59	12.91	14.96	16.47	16.43	16.52	16.66	16.11	16.02	16.71	15.38	\$15.20	\$21.11	0.8014
1995	16.16	17.14	17.31	18.36	18.43	17.43	16.23	16.72	16.65	15.96	15.88	16.94	\$16.93	\$23.02	0.8184
1996	17.23	17.78	20.40	22.04	19.65	18.98	19.79	19.90	21.69	22.60	21.50	23.66	\$20.44	\$27.26	0.8342
1997	23.57	21.03	20.07	18.54	19.41	17.3	17.48	17.98	18.09	19.59	18.33	16.39	\$18.98	\$24.86	1990-1999 0.8495
1998	14.79	13.39	12.25	12.41	12.31	11.62	12.92	12.49	14.13	13.38	11.47	9.39	\$12.55	\$16.23	Real Avg.: 0.8603
1999	10.69	10.43	13.07	15.64	15.86	15.82	18.16	20.08	22.96	21.83	23.65	24.54	\$17.73	\$22.63	\$24.10 0.8717
2000	25.74	27.65	28.01	23.83	27.15	29.62	27.63	29.40	32.25	31.56	32.74	23.72	\$28.28	\$35.39	0.8889
2001	24.37	26.02	24.70	25.55	26.70	25.82	24.60	24.12	23.21	19.45	17.23	16.69	\$23.21	\$28.38	0.9099
2002	17.52	19.14	22.76	24.99	25.87	24.16	25.82	27.39	28.76	27.53	24.69	28.03	\$24.72	\$29.74	0.9249
2003	31.91	35.20	32.59	25.59	26.19	29.35	29.17	30.22	27.09	28.55	29.11	30.67	\$29.64	\$34.93	0.9442
2004	33.10	33.66	35.50	35.43	39.07	36.73	39.44	43.12	42.71	48.56	42.15	36.66	\$38.84	\$44.63	0.9684
2005	41.12	43.59	50.63	49.75	46.77	53.67	56.67	62.40	63.47	60.37	56.11	57.17	\$53.48	\$59.50	1.0000
2006	62.85	59.26	60.61	67.74	69.32	69.50	73.10	71.74	62.33	54.27	54.26	58.13	\$63.59	\$68.42	1.0342
2007	51.52	57.00	59.01	63.92	64.76	69.11	75.93	73.83	79.72	84.77	92.98	88.64	\$71.77	\$74.95	2000-2009 1.0654
2008	91.16	94.12	105.06	112.37	125.41	133.78	132.87	115.98	101.86	73.65	53.94	37.70	\$98.16	\$100.22	Real Avg.: 1.0898
2009	39.01	42.78	47.75	46.56	58.23	69.80	64.53	71.52	69.20	74.28	76.52	75.12	\$61.28	\$61.74	\$53.79 1.1043
2010	79.34	76.74	79.45	82.23	74.23	75.66	76.53	75.78	75.27	82.41	83.93	89.75	\$79.28	\$79.28	1.1127
2011	92.56														1.1276

Sources:

Oil Prices: Accessed February 2011 at Alaska Department of Revenue (<http://www.tax.alaska.gov/programs/oil/oilprices/ans.aspx>)

(Spot prices are unaudited and do not reflect Production Tax Settlement Values.)

Gross Domestic Product Index: White House, *Budget for Fiscal Year 2012, Historical Tables*, "Gross Domestic Product and Deflators," pp. 211-212.

(2011 GDP deflator estimated.)

Appendix C

**Alyeska Pipeline Service Company Cold Restart History, 1997-2007:
Extracts from Selected Documents A – 9**

Alyeska Pipeline Service Company Cold Restart History, 1997-2007:
Selected Documents

Cold Restart Procedures
(1997-1998)

Sept. 2, 1997 – (JPO Memorandum)

“Significant Issues: The Cold Restart Procedure is scheduled to be issued August 1998.”

Robert Krenzelok, T&DR, “Cold Restart: TAPS Design Basis Compliance,” Sept. 2, 1997 (JPO Document #19970911-19), p. 1. (Memorandum to Jerry Brossia [Authorized Officer, Bureau of Land Management] and Bill Britt [State Pipeline Coordinator].)

July 6, 1998 – (JPO Memorandum)

“Significant Issues: The Cold Restart procedure is behind schedule and will not be completed until second quarter 1999. This project lacks management support.”

Robert Krenzelok, T&DR, “Cold Restart: TAPS Design Basis Compliance,” July 6, 1998 (JPO Document #19980714-5), p. 1. (Memorandum to Jerry Brossia [Authorized Officer, Bureau of Land Management] and Bill Britt [State Pipeline Coordinator], states in part: “Completion of the Cold Restart Procedure is being delayed for the second time.”)

July 6, 1998 – (JPO Letter)

“Alyeska personnel . . . have indicated milestones necessary to support the mid September 1998 completion of the Cold Restart Procedure have not been met and additional line items within the submitted milestone schedule are no longer valid.”

Letter from Jerry Brossia (Authorized Officer, Bureau of Land Management) and Bill Britt (State Pipeline Coordinator) to William D. Howitt (Vice President, Corporate Services Division, Alyeska Pipeline Service Co.), July 6, 1998 (JPO Document #1998-713-11).

August 13, 1998 – (Alyeska Letter)

[Letter in response to JPO letter requesting new milestone schedule for the Cold Restart Procedure.] “When Pump Stations 8 & 10 were shut down, since they were essential parts of the original Cold Restart Procedure, a new procedure was required.” [The new project is in 3 parts. . . .]

(1) Rheology Study: . . . “The final delivery . . . is expected to be early November of this year.”

(2) Cool Down Calculation: . . . “The current rough schedule is for the radial heat transfer model to be completed sometime in March of 1999.”

(3) Generation of new Cold Start Procedure: . . . “GSE systems has been contracted The current delivery date that GSE has proposed is December 15, 1998.”

Letter from Emery. L Monthei (Maintenance Reliability Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Cold Restart Procedure,” Aug. 13, 1998 (JPO Document # 19980821-8).

Cold Restart Procedures (continued)
(1999-2000)

August 12, 1999 – (Alyeska Letter)

[Cold Restart Study testing procedures have] “proven to be a difficult time consuming process. . . . Many of these procedures are new and on the leading edge of technology. . . . Once a new schedule is completed, we will review with plan with JPO.”

Letter from E. Lee Monthei (Maintenance Reliability Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Cold Restart Study,” Aug. 12, 1999 (JPO Document # 19990817-25).

October 21, 1999 – (Alyeska Letter)

“Preliminary testing to date has shown that TAPS Crude Oil indicates properties of Newtonian Behavior to -20F. This is good news. . . allowing for the modeling to be completed within the expected time frame. . . . A final report for this study will then be finalized by the end of May 2000.”

Letter from E. Lee Monthei (Maintenance Reliability Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Cold Restart Study,” Oct. 21, 1999 (JPO Document # 19991026-10).

April 28, 2000 – (Alyeska Letter)

“The next project milestone is to develop and finalize the hydraulic model. . . . Our next update is planned for the end of June, 2000.”

Letter from E. Lee Monthei (Maintenance Reliability Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Cold Restart Study,” April 28, 2000 (JPO Document # 20000508-29).

July 24, 2000 – (Alyeska Letter)

“As you know, there have been changes to the crude mix in the last few years and we have ramped-down pumps stations [sic.], both of which have affected our cold re-start plans and procedures. . . . Alyeska will have in place, by November of 2000, when this type of cold weather becomes a possibility, a procedure that sets the interim parameters for re-start of the pipeline in extreme winter conditions. A permanent cold restart plan and re-start procedure will be put in place once we have all the data needed to complete the analysis and design.”

Letter from William D. Howitt (Senior Vice President, Alyeska Pipeline Service Company) to Joint Pipeline Office, “Re: Cold Restart Study and Interim Plan for Winter of 2000,” July 24, 2000 (JPO Document # 20000725-2).

December 13, 2000 – (Alyeska Letter)

“A formal meeting was held on December 8, 2000 in the JPO Offices to review the Interim Cool Restart Procedure, revise schedule of the hydraulic modeling associated with the TAPS Crude Oil Study, and Cold Restart Construction Schedule. . . . The revised schedule shows the following deliverable dates: Cold Restart Computer Modeling complete by 8/3/01; Cold Restart Procedure complete by 9/11/01; Cold Restart Piping will be complete by 8/27/01; and Final Report on Cold Restart Procedure by 11/01/01.”

Letter from E. Lee Monthei (Maintenance Reliability Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Interim Cool Restart Procedure, Revised Schedules-TAPS Crude Oil Studies (FO45)/Cold Restart Piping Project (F264),” December 13, 2000 (JPO Document # 20001218-20).

Cold Restart Procedures (continued)
(2002-2005)

Cold Restart Window (Original 21-day Design Basis capability reduced to 14 days)

March 14, 2002 – (JPO Letter)

“. . . the allowable cold restart times under contingency weather conditions is less than the original Design Basis estimated time of 21 days. Please provide the following information. . . . (3) A discussion of the operational constraints on pipeline startup with pipe steel temperatures below -20F°. (4) The Cold Restart Study calls for possible back flow of oil to the upstream Pump Stations. In light of the recent Check Valve 50 event during oil back flow, provide documentation/test information to show this will be a safe practice.”

Letter from Jerry Brossia (Authorized Officer, BLM/OIPM) and John Kerrigan (State Pipeline Coordinator) to Robert L. Shoaf (Vice President, Alyeska Pipeline Service Co.), March 14, 2002 (JPO Document #20020319-13).

March 16, 2005 – (Alyeska Letter)

“In accordance with DB 180, Section 1.1.6, we request your approval for the proposed change to DB-180, Section 2.12.1.7 Restarting After Extended Winter Shutdown. . . . These sections have been modified to reflect the findings of the 1997 to 2002 Cold Restart Investigation.”

Letter from E. Lee Monthei (Vice President, Alyeska Pipeline Service Company) to Joint Pipeline Office, “Subject: Design Basis Revision for DB-180, Section 2.12.1.7 Restarting After Extended Winter Shutdown,” March 16, 2005 (JPO Document # 20050316-7).

June 29, 2005 – (JPO Letter)

“The JPO acknowledges Alyeska current engineering judgment that there is now only a minimum of a 14 day shutdown window under arctic winter conditions as opposed to the 21 day ‘Original Cold Restart Plan.’ In light of this 14 day window, request that Alyeska address the issues related to repair scenarios which can not be performed in 14 days.”

Letter from Jerry Brossia (Authorized Officer, BLM/OIPM) and Frederick M. Thompson (Acting State Pipeline Coordinator) to Robert L. Shoaf (JPO Executive Liaison, Alyeska Pipeline Service Co.), June 29, 2005 (JPO Document #20050630-5).

Cold Restart Procedures (continued)
(2005-2007)

(Pump Station #12 Role in Cold Restart Procedures)

November 9, 2005 – (Alyeska Letter)

“The original Alyeska project schedule for the PS12 cold restart equipment and piping modifications . . . provided for work to be completed prior to severe cold weather this winter. This work . . . will be fully in place by mid-February 2006. With project delays, we are taking steps to create an alternate capability while completing purchase and set up of our original design.”

Letter from G. Wyche Ford (Company-Wide Projects Mgr., Alyeska Pipeline Service Company) to Joint Pipeline Office, “Reference: Government Letter No.: 05-091-RN, PS12 Cold Restart Implementation,” November 9, 2005 (JPO Document # 20051114-4).

November 17, 2005 – (JPO Letter)

“Alyeska indicates that the PS 12 Cold Restart equipment will not be available until mid-February 2006. . . .engineering and contract required for the alternate capacity are not yet in place. . . . until Alyeska has the fully engineerted equipment and procedures for a cold winter restart at Pump Station 12 the following Finding of deficiency will remain open:

ANC-05-E-054-F/01-Finding: Contrary to the requirements of Stipulation 1.21.1, Alyeska does not have adequate equipment procedures in place to handle a cold winter restart at Pump Station 12.”

Letter from Jerry Brossia (Authorized Officer, BLM/OPM) and Frederick M. Thompson (Acting State Pipeline Coordinator) to Robert I. Shoaf (JPO Executive Liaison, Alyeska Pipeline Service Co.), January 12, 2006 (JPO Document #20051122-7).

January 12, 2006 – (JPO Letter)

“Since Alyeska indicates in their letter that fully engineered equipment for a cold winter restart at Pump Station 12 is not in place. . . the Finding ANC-05-E-054-F/01 remains open.

ANC-05-E-054-F/01-Finding: Contrary to the requirements of Stipulation 1.21.1, Alyeska does not have adequate equipment procedures in place to handle a cold winter restart at Pump Station 12.”

Letter from Jerry Brossia (Authorized Officer, BLM/OPM) and Frederick M. Thompson (Acting State Pipeline Coordinator) to Robert I. Shoaf (Compliance Officer, Alyeska Pipeline Service Co.), January 12, 2006 (JPO Document #20060113-3).

January 10, 2007 – (Alyeska Letter)

“This letter provides notification that the cold restart procedures for PS-12 have been finalized and were placed in the TAPS documents system for use on December 1, 2006. . . . Personnel at the Glennallen Response Base have received training on these procedures and are prepared to initiate equipment mobilization and the PS-12 specific cold restart procedures should the need arise.”

Letter from James F. Johnson (Pipeline Vice President, Alyeska Pipeline Service Co.), to Joint Pipeline Office, January 10, 2007 (JPO Document #20070111-8).

Appendix D

Extracts from ConocoPhillips 10-K Reports (Future Profitability) A - 13

CONOCOPHILLIPS (COP)

10-K

Annual report pursuant to section 13 and 15(d)

Filed on 02/23/2011

Filed Period 12/31/2010



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Results of Operations

Year Ended December 31, 2010	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
<i>Consolidated operations</i>										
Sales	\$ 3,645	3,600	7,245	2,379	5,967	-	4,958	1,743	-	22,292
Transfers	2,693	2,389	5,082	246	2,278	-	770	450	-	8,826
Other revenues	-	559	559	3,216	142	-	55	172	18	4,162
Total revenues	6,338	6,548	12,886	5,841	8,387	-	5,783	2,365	18	35,280
Production costs excluding taxes	849	1,230	2,079	873	1,004	-	538	296	-	4,790
Taxes other than income taxes	1,570	498	2,068	74	6	1	355	18	1	2,523
Exploration expenses	37	292	329	295	146	2	260	29	101	1,162
Depreciation, depletion and amortization	529	2,231	2,760	1,666	1,972	2	1,206	202	-	7,808
Impairments	4	19	23	13	43	-	-	-	-	79
Transportation costs	528	424	952	134	281	-	119	23	-	1,509
Other related expenses	(38)	112	74	41	42	17	(48)	(10)	62	178
Accretion	58	55	113	50	192	-	24	-	4	383
	2,801	1,687	4,488	2,695	4,701	(22)	3,329	1,807	(150)	16,848
Provision for income taxes	1,014	555	1,569	108	3,066	(23)	1,361	1,458	(28)	7,511
Results of operations for producing activities	1,787	1,132	2,919	2,587	1,635	1	1,968	349	(122)	9,337
Other earnings	(52)	(99)	(151)	(72)	76	16	139	29	8	45
Net income (loss) attributable to ConocoPhillips	\$ 1,735	1,033	2,768	2,515	1,711	17	2,107	378	(114)	9,382
<i>Equity affiliates</i>										
Sales	\$ -	-	-	955	-	5,189	249	-	-	6,393
Transfers	-	-	-	-	-	1,876	-	-	-	1,876
Other revenues	-	-	-	7	-	1,219	10	-	-	1,236
Total revenues	-	-	-	962	-	8,284	259	-	-	9,505
Production costs excluding taxes	-	-	-	265	-	544	59	-	-	868
Taxes other than income taxes	-	-	-	4	-	3,463	42	-	-	3,509
Exploration expenses	-	-	-	-	-	61	(2)	-	-	59
Depreciation, depletion and amortization	-	-	-	190	-	568	55	-	-	813
Impairments	-	-	-	-	-	645	-	-	-	645
Transportation costs	-	-	-	-	-	784	25	-	-	809
Other related expenses	-	-	-	(3)	-	-	44	-	-	41
Accretion	-	-	-	2	-	7	2	-	-	11
	-	-	-	504	-	2,212	34	-	-	2,750
Provision for income taxes	-	-	-	128	-	647	(25)	-	-	750
Results of operations for producing activities	-	-	-	376	-	1,565	59	-	-	2,000
Other earnings	-	-	-	-	-	405	(86)	-	-	319
Net income (loss) attributable to ConocoPhillips	\$ -	-	-	376	-	1,970	(27)	-	-	2,319

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Year Ended
December 31, 2009

Millions of Dollars

	Alaska*	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
<i>Consolidated operations</i>										
Sales	\$ 3,353	3,144	6,497	2,179	4,995	-	3,830	1,562	11	19,074
Transfers	2,261	1,937	4,198	345	2,305	-	500	257	-	7,605
Other revenues	30	54	84	168	(66)	-	10	136	54	386
Total revenues	5,644	5,135	10,779	2,692	7,234	-	4,340	1,955	65	27,065
Production costs excluding taxes	864	1,266	2,130	1,011	1,048	-	445	270	8	4,912
Taxes other than income taxes	1,135	422	1,557	75	3	1	165	17	7	1,825
Exploration expenses	74	426	500	201	156	4	212	32	75	1,180
Depreciation, depletion and amortization	611	2,615	3,226	1,689	2,016	2	910	201	11	8,055
Impairments	-	5	5	296	104	-	12	-	51	468
Transportation costs	548	392	940	135	267	-	111	24	5	1,482
Other related expenses	251	60	311	(3)	62	3	121	23	14	531
Accretion	49	55	104	41	191	-	19	3	3	361
	2,112	(106)	2,006	(753)	3,387	(10)	2,345	1,385	(109)	8,251
Provision for income taxes	716	(79)	637	(309)	2,280	(3)	1,093	1,186	(21)	4,863
Results of operations for producing activities	1,396	(27)	1,369	(444)	1,107	(7)	1,252	199	(88)	3,388
Other earnings	144	(10)	134	(91)	(59)	(5)	132	4	(1)	114
Net income (loss) attributable to ConocoPhillips	\$ 1,540	(37)	1,503	(535)	1,048	(12)	1,384	203	(89)	3,502

Equity affiliates

Sales	\$ -	-	-	713	-	3,783	74	-	-	4,570
Transfers	-	-	-	-	-	1,946	-	-	-	1,946
Other revenues	-	-	-	(2)	-	-	1	-	-	(1)
Total revenues	-	-	-	711	-	5,729	75	-	-	6,515
Production costs excluding taxes	-	-	-	213	-	501	26	-	-	740
Taxes other than income taxes	-	-	-	3	-	2,270	4	-	-	2,277
Exploration expenses	-	-	-	-	-	37	2	-	-	39
Depreciation, depletion and amortization	-	-	-	133	-	455	21	-	-	609
Impairments**	-	-	-	-	-	83	-	-	-	83
Transportation costs	-	-	-	-	-	703	3	-	-	706
Other related expenses	-	-	-	17	-	3	1	-	-	21
Accretion	-	-	-	1	-	6	1	-	-	8
	-	-	-	344	-	1,671	17	-	-	2,032
Provision for income taxes	-	-	-	89	-	326	9	-	-	424
Results of operations for producing activities	-	-	-	255	-	1,345	8	-	-	1,608
Other earnings**	-	-	-	-	-	(201)	(86)	-	-	(287)
Net income (loss) attributable to ConocoPhillips	\$ -	-	-	255	-	1,144	(78)	-	-	1,321

*Certain amounts were reclassified between "Sales" and "Transfers," as well as between "Other revenues" and "Other related expenses." Total Results of operations was unchanged.

**Goodwill considered to be a non-oil-and-gas producing activity was reclassified from "Impairments" to "Other earnings."

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Year Ended December 31, 2008	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
<i>Consolidated operations</i>										
Sales	\$ 5,771	6,726	12,497	4,386	8,061	-	4,787	2,075	290	32,096
Transfers	3,444	3,401	6,845	-	3,415	-	579	669	-	11,508
Other revenues	(25)	98	73	317	477	-	40	230	(16)	1,121
Total revenues	9,190	10,225	19,415	4,703	11,953	-	5,406	2,974	274	44,725
Production costs excluding taxes	960	1,405	2,365	887	1,157	-	428	245	34	5,116
Taxes other than income taxes	3,432	764	4,196	61	29	2	295	27	205	4,815
Exploration expenses	99	469	568	240	235	4	148	41	103	1,339
Depreciation, depletion and amortization	559	2,426	2,985	1,802	1,917	2	733	215	24	7,678
Impairments*	-	620	620	92	72	-	9	-	-	793
Transportation costs	409	519	928	140	302	-	115	29	10	1,524
Other related expenses	(38)	108	70	56	(306)	18	113	6	53	10
Accretion	40	59	99	33	196	-	14	4	3	349
	3,729	3,855	7,584	1,392	8,351	(26)	3,551	2,407	(158)	23,101
Provision for income taxes	1,317	1,310	2,627	371	5,241	7	1,640	2,094	(46)	11,934
Results of operations for producing activities	2,412	2,545	4,957	1,021	3,110	(33)	1,911	313	(112)	11,167
Other earnings	(97)	128	31	243	314	66	46	(35)	(11)	654
Net income (loss) attributable to ConocoPhillips	\$ 2,315	2,673	4,988	1,264	3,424	33	1,957	278	(123)	11,821
<i>Equity affiliates</i>										
Sales	\$ -	-	-	644	-	6,890	9	-	-	7,543
Transfers	-	-	-	-	-	4,660	-	-	-	4,660
Other revenues	-	-	-	45	-	-	-	-	-	45
Total revenues	-	-	-	689	-	11,550	9	-	-	12,248
Production costs excluding taxes	-	-	-	182	-	730	4	-	-	916
Taxes other than income taxes	-	-	-	3	-	5,725	-	-	-	5,728
Exploration expenses	-	-	-	-	-	87	-	-	-	87
Depreciation, depletion and amortization	-	-	-	84	-	550	9	-	-	643
Impairments	-	-	-	-	-	7,038	-	-	-	7,038
Transportation costs	-	-	-	-	-	910	1	-	-	911
Other related expenses	-	-	-	1	-	7	5	-	-	13
Accretion	-	-	-	1	-	5	-	-	-	6
	-	-	-	418	-	(3,502)	(10)	-	-	(3,094)
Provision for income taxes	-	-	-	132	-	1,070	(11)	-	1	1,192
Results of operations for producing activities	-	-	-	286	-	(4,572)	1	-	(1)	(4,286)
Other earnings	-	-	-	3	-	(410)	(3)	-	-	(410)
Net income (loss) attributable to ConocoPhillips	\$ -	-	-	289	-	(4,982)	(2)	-	(1)	(4,696)

*Excludes goodwill impairment of \$25,443 million.

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Capitalized Costs

At December 31

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia*	Asia Pacific/ Middle East	Africa	Other Areas	Total
2010										
<i>Consolidated operations</i>										
Proved properties	\$ 12,268	32,076	44,344	20,037	21,547	9	11,199	3,595	3,921	104,652
Unproved properties	1,471	1,700	3,171	1,930	328	1	1,113	163	249	6,955
	13,739	33,776	47,515	21,967	21,875	10	12,312	3,758	4,170	111,607
Accumulated depreciation, depletion and amortization	5,758	13,362	19,120	10,281	13,636	7	4,690	1,370	10	49,114
	\$ 7,981	20,414	28,395	11,686	8,239	3	7,622	2,388	4,160	62,493
<i>Equity affiliates</i>										
Proved properties	\$ -	-	-	4,812	-	1,923	2,320	-	-	9,055
Unproved properties	-	-	-	1,794	-	146	8,144	-	-	10,084
	-	-	-	6,606	-	2,069	10,464	-	-	19,139
Accumulated depreciation, depletion and amortization	-	-	-	512	-	1,584	84	-	-	2,180
	\$ -	-	-	6,094	-	485	10,380	-	-	16,959
2009										
<i>Consolidated operations</i>										
Proved properties	\$ 11,678	33,408	45,086	21,070	20,759	9	10,398	3,170	3,235	103,727
Unproved properties	1,421	1,407	2,828	1,899	396	-	970	195	218	6,506
	13,099	34,815	47,914	22,969	21,155	9	11,368	3,365	3,453	110,233
Accumulated depreciation, depletion and amortization	5,218	13,464	18,682	8,919	11,995	5	3,578	1,167	43	44,389
	\$ 7,881	21,351	29,232	14,050	9,160	4	7,790	2,198	3,410	65,844
<i>Equity affiliates</i>										
Proved properties	\$ -	-	-	3,912	-	12,796	1,511	-	-	18,219
Unproved properties	-	-	-	1,681	-	956	6,840	-	-	9,477
	-	-	-	5,593	-	13,752	8,351	-	-	27,696
Accumulated depreciation, depletion and amortization	-	-	-	299	-	9,026	36	-	-	9,361
	\$ -	-	-	5,294	-	4,726	8,315	-	-	18,335

*2009 equity affiliates adjusted to reclassify certain costs between proved and unproved, as well as to include amounts determined to be capitalized.

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P and LUKOIL Investment segments, excluding pipeline and marine operations, liquefied natural gas operations, crude oil and natural gas marketing activities and downstream operations.
- Proved properties include capitalized costs for leaseholds holding proved reserves, development wells and related equipment and facilities (including uncompleted development well costs), mining facilities associated with our synthetic oil operations and support equipment.
- Unproved properties include capitalized costs for leaseholds under exploration (including where hydrocarbons were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with SEC and FASB requirements, amounts for 2010 and 2009 were computed using 12-month average prices and end-of-year costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Amounts for 2008 were computed using end-of-year prices and costs. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/Middle East	Africa	Other Areas	Total
2010										
<i>Consolidated operations</i>										
Future cash inflows	\$102,743	68,949	171,692	38,083	49,270	-	37,673	24,487	8,466	329,671
Less:										
Future production and transportation costs*	57,899	29,749	87,648	16,753	12,899	-	10,480	4,142	3,007	134,929
Future development costs	8,792	12,700	21,492	11,161	10,295	-	2,226	1,133	3,050	49,357
Future income tax provisions	13,383	9,024	22,407	2,416	16,765	-	9,211	16,217	384	67,400
Future net cash flows	22,669	17,476	40,145	7,753	9,311	-	15,756	2,995	2,025	77,985
10 percent annual discount	10,723	7,551	18,274	3,890	2,597	-	4,889	1,025	2,368	33,043
Discounted future net cash flows	\$ 11,946	9,925	21,871	3,863	6,714	-	10,867	1,970	(343)	44,942
<i>Equity affiliates</i>										
Future cash inflows	\$ -	-	-	47,169	-	5,610	32,845	-	-	85,624
Less:										
Future production and transportation costs*	-	-	-	16,492	-	4,809	21,036	-	-	42,337
Future development costs	-	-	-	4,684	-	85	295	-	-	5,064
Future income tax provisions	-	-	-	6,649	-	(80)	2,082	-	-	8,651
Future net cash flows	-	-	-	19,344	-	796	9,432	-	-	29,572
10 percent annual discount	-	-	-	13,453	-	293	4,732	-	-	18,478
Discounted future net cash flows	\$ -	-	-	5,891	-	503	4,700	-	-	11,094
<i>Total company</i>										
Discounted future net cash flows	\$ 11,946	9,925	21,871	9,754	6,714	503	15,567	1,970	(343)	56,036

*Includes taxes other than income taxes.

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	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa*	Other Areas	Total
2009										
<i>Consolidated operations</i>										
Future cash inflows	\$74,359	51,007	125,366	45,965	41,832	-	31,276	19,618	6,416	270,473
Less:										
Future production and transportation costs**	44,789	32,491	77,280	23,625	13,559	-	9,058	3,832	2,071	129,425
Future development costs	7,829	8,350	16,179	12,769	10,369	-	2,284	1,142	3,879	46,622
Future income tax provisions	7,519	2,992	10,511	2,183	10,676	-	7,288	12,396	71	43,125
Future net cash flows	14,222	7,174	21,396	7,388	7,228	-	12,646	2,248	395	51,301
10 percent annual discount	6,474	2,300	8,774	3,703	1,878	-	4,108	879	1,566	20,908
Discounted future net cash flows	\$ 7,748	4,874	12,622	3,685	5,350	-	8,538	1,369	(1,171)	30,393
<i>Equity affiliates</i>										
Future cash inflows	\$ -	-	-	36,540	-	69,277	19,420	-	-	125,237
Less:										
Future production and transportation costs*	-	-	-	13,689	-	49,874	13,891	-	-	77,454
Future development costs	-	-	-	4,481	-	7,795	350	-	-	12,626
Future income tax provisions	-	-	-	4,785	-	2,265	694	-	-	7,744
Future net cash flows	-	-	-	13,585	-	9,343	4,485	-	-	27,413
10 percent annual discount	-	-	-	9,512	-	4,002	2,018	-	-	15,532
Discounted future net cash flows	\$ -	-	-	4,073	-	5,341	2,467	-	-	11,881
<i>Total company</i>										
Discounted future net cash flows	\$ 7,748	4,874	12,622	7,758	5,350	5,341	11,005	1,369	(1,171)	42,274

*Restated to include amounts omitted and to reclassify between production costs, development costs and taxes.

**Includes taxes other than income taxes.

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2008	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa*	Other Areas	Total
<i>Consolidated operations</i>										
Future cash inflows	\$54,662	51,354	106,016	19,632	42,230	-	22,626	12,478	4,357	207,339
Less:										
Future production and transportation costs**	35,150	30,508	65,658	9,357	12,217	-	6,960	3,229	2,000	99,421
Future development costs	9,681	10,443	20,124	4,188	8,835	-	2,859	800	2,084	38,890
Future income tax provisions	3,227	3,439	6,666	401	11,679	-	4,880	6,919	248	30,793
Future net cash flows	6,604	6,964	13,568	5,686	9,499	-	7,927	1,530	25	38,235
10 percent annual discount	2,159	2,886	5,045	1,222	3,178	-	2,998	541	703	13,687
Discounted future net cash flows	\$ 4,445	4,078	8,523	4,464	6,321	-	4,929	989	(678)	24,548
<i>Equity affiliates</i>										
Future cash inflows	\$ -	-	-	17,055	-	36,679	15,798	-	-	69,532
Less:										
Future production and transportation costs*	-	-	-	12,820	-	30,137	10,536	-	-	53,493
Future development costs	-	-	-	3,010	-	5,200	611	-	-	8,821
Future income tax provisions	-	-	-	252	-	260	379	-	-	891
Future net cash flows	-	-	-	973	-	1,082	4,272	-	-	6,327
10 percent annual discount	-	-	-	894	-	119	2,281	-	-	3,294
Discounted future net cash flows	\$ -	-	-	79	-	963	1,991	-	-	3,033
<i>Total company</i>										
Discounted future net cash flows	\$ 4,445	4,078	8,523	4,543	6,321	963	6,920	989	(678)	27,581

*Restated to include amounts omitted and to reclassify between production costs, development costs and taxes.

**Includes taxes other than income taxes.

Excludes discounted future net cash flows from Canadian Syncrude of \$435 million.

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2010	2009*	2008*	2010	2009	2008	2010	2009	2008
Discounted future net cash flows at the beginning of the year	\$ 30,393	24,548	67,162	11,881	3,033	20,027	42,274	27,581	87,189
Changes during the year									
Revenues less production and transportation costs for the year**	(22,296)	(18,460)	(32,149)	(3,083)	(2,793)	(4,648)	(25,379)	(21,253)	(36,797)
Net change in prices, and production and transportation costs***	39,532	19,208	(72,850)	3,478	14,386	(20,766)	43,010	33,594	(93,616)
Extensions, discoveries and improved recovery, less estimated future costs	4,517	2,312	1,759	297	1,342	181	4,814	3,654	1,940
Development costs for the year	5,617	6,148	7,715	1,758	1,623	2,622	7,375	7,771	10,337
Changes in estimated future development costs	(3,722)	(7,036)	(3,270)	(129)	(2,197)	(813)	(3,851)	(9,233)	(4,083)
Purchases of reserves in place, less estimated future costs	19	3	10	-	96	321	19	99	331
Sales of reserves in place, less estimated future costs	(3,729)	(75)	(52)	(5,405)	-	(33)	(9,134)	(75)	(85)
Revisions of previous quantity estimates**	3,062	5,149	1,904	372	(1,597)	(1,689)	3,434	3,552	215
Accretion of discount	5,000	3,972	11,765	1,404	365	2,456	6,404	4,337	14,221
Net change in income taxes	(13,451)	(5,376)	42,554	521	(2,377)	5,375	(12,930)	(7,753)	47,929
Total changes	14,549	5,845	(42,614)	(787)	8,848	(16,994)	13,762	14,693	(59,608)
Discounted future net cash flows at year end	\$ 44,942	30,393	24,548	11,094	11,881	3,033	56,036	42,274	27,581

*Restated to include amounts omitted in the Africa geographic area.

**Includes taxes other than income taxes.

***Includes amounts resulting from changes in the timing of production.

- The net change in prices, and production and transportation costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.
- For 2010 and 2009, as required, purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent. For 2008, the end-of-year sales prices were used, as required.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production, transportation and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions.

COP 10-K DATA FOR FIGURES 5 THRU 7

ConocoPhillips Standardized NPV10 of Proved Reserves * (Data and Sources)

2010			Europe			Asia			CP Avg.
	Alaska	Lower 48	(incl. North Sea)	Russia	Pacific/Middle East	Africa	Other Areas	(without Alaska)	
Capitalized costs	\$7,981	\$20,414	\$17,780	\$8,239	\$488	\$18,002	\$2,388	\$4,160	\$71,471
Discounted future net cash flows	\$11,946	\$9,925	\$9,754	\$6,714	\$503	15,567	\$1,970	(\$343)	\$44,090
ratio	1.50	0.49	0.55	0.81	1.03	0.86	0.82	(0.08)	0.62
ANS Year-end Price	\$89.75 **								
2009			Europe			Asia			CP Avg.
	Alaska	Lower 48	(incl. North Sea)	Russia	Pacific/Middle East	Africa	Other Areas	(without Alaska)	
Capitalized costs	\$7,881	\$21,351	\$19,344	\$9,160	\$4,730	\$16,105	\$2,198	\$3,410	\$76,298
Discounted future net cash flows	\$7,748	\$4,874	\$7,758	\$5,350	\$5,341	11,005	\$1,369	(\$1,171)	\$34,526
ratio	0.98	0.23	0.40	0.58	1.13	0.68	0.62	(0.34)	0.45
ANS Year-end Price	\$75.59 **								
2008					Russia	Asia			CP Avg.
	Alaska	Lower 48	Canada	Europe	and Caspian	Pacific / Middle East	Africa	Other Areas	(without Alaska)
Capitalized costs	\$7,626	\$22,159	\$15,495	\$8,719	\$4,590	\$13,470	\$2,163	\$2,717	\$69,313
Discounted future net cash flows	\$4,445	\$4,078	\$4,543	\$6,321	\$963	\$6,920	\$901	(\$678)	\$23,048
ratio	0.58	0.18	0.29	0.72	0.21	0.51	0.42	(0.25)	0.33
ANS Year-end Price	\$38.49 **								

COP 10-K DATA FOR FIGURES 5 THRU 7

ConocoPhillips Standardized NPV10 of Proved Reserves * (Data and Sources)

	Alaska	Lower 48	Canada	Europe	Russia and Caspian	Asia Pacific	Middle East and Africa	Other Areas	CP Avg. (without Alaska)
2007									
Capitalized costs	\$6,872	\$21,862	\$19,024	\$11,687	\$12,056	\$6,654	\$2,866	\$220	\$74,369
Discounted future net cash flows	\$15,185	\$16,120	\$12,098	\$13,245	\$12,136	\$11,122	\$7,232	\$51	\$72,004
ratio	2.21	0.74	0.64	1.13	1.01	1.67	2.52	0.23	0.97
ANS Year-end Price	\$92.58	**							
2006									
Capitalized costs	\$6,834	\$21,747	\$13,085	\$10,688	\$10,093	\$6,032	\$2,341	\$3,695	\$67,681
Discounted future net cash flows	\$11,691	\$14,615	\$6,206	\$9,388	\$5,012	\$8,118	\$3,396	\$5,597	\$52,332
ratio	1.71	0.67	0.47	0.88	0.50	1.35	1.45	1.51	0.77
ANS Year-end Price	\$62.54	**							

* Includes minority interests in equity affiliates.

** December average ANS WC spot price, posted by ADOR (adjusted for inflation)

Sources:

2006: CP, Annual Financial Report for 2006, pp. 109-110.

2007: CP, Proxy Statement for CY 2008 on Form 10-K, pp. 163, 165

2008: CP, Proxy Statement for CY 2009 on Form 10-K, pp. A-135-137

2009: CP, Proxy Statement for CY 2010 on Form 10-K, pp. 160-162

2010: CP, Proxy Statement for CY 2010 on Form 10-K, pp. 160, 161.

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