PRINCE WILLIAM SOUND RCAC

Regional Citizens' Advisory Council / *"Citizens promoting environmentally safe operation of the Alyeska terminal and associated tankers."*

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MEMORANDUM

DATE: June 2, 2005

SUBJECT: Prince William Sound Regional Citizens' Advisory Council Report: "The Profitability and Economic Viability of Alaska North Slope"

FROM: John S. Devens, Ph.D., Executive Director

John Devens

This report is an analysis by Dr. Richard Fineberg, a Fairbanks-based economic consultant, commissioned by the Prince William Sound Regional Citizens' Advisory Council (PWSRCAC).

The PWSRCAC is an independent non-profit corporation whose mission is to promote environmentally safe operation of the Valdez Marine Terminal and associated tankers. Our work is guided by the Oil Pollution Act of 1990, and our contract with Alyeska Pipeline Service Company. PWSRCAC's 18 member organizations are communities in the region affected by the 1989 Exxon Valdez oil spill, as well as commercial fishing, aquaculture, Native, recreation, tourism and environmental groups.

The PWSRCAC commissioned this report to address claims by the oil industry that it needs to reduce certain environmental protections in Prince William Sound, or is unable to add new protections, because of financial reasons. By obtaining the information contained in this report, we hope to show how the cost of environmental amenities and safeguards compare to industry profits. Key findings of this report include:

- Oil industry profits on the North Slope were $5.5 billion in 2004, when prices averaged $38.84 a barrel. That's about $15 million a day, or $625,000 an hour.
- Even in 1998, when prices averaged $12.55 a barrel, the industry made $825 million on the North Slope.
- At prices of $50 a barrel, the industry's North Slope profits would amount to about $5.7 billion a year.

These findings put into perspective some of the industry's costs for environmental protection in Prince William Sound, and its claims that cost reductions are needed:

- The existing tug system costs about $25 million a year to operate, according to Alyeska. At $15 million a day, that is about 40 hours worth of profits.
- Industry representatives, including Alyeska's president, have discussed cutting the tug fleet. Eliminating one tug could save about $2.5 million annually, or 4 hours of profits.
- A new enhanced tractor tug costs approximately $22 million, or the equivalent of approximately 1 and 1/2 days of profits.
- The new double hulled, fully redundant tankers being built by some shipping companies for the trans-Alaska pipeline system trade cost approximately $250 million, the equivalent of approximately 16 and 1/2 days of profits.
- The PWSRCAC has long advocated the installation of vapor controls on Alyeska's ballast water treatment facility, the single largest remaining source of cancer-causing hydrocarbon emissions at the Valdez tanker terminal. According to engineering estimates obtained by the PWSRCAC, the cost of controlling emissions from the two largest sources within the treatment facility is only about $1.5 million, just over two hours worth of industry profits.

It is the goal of the PWSRCAC to use the information contained in this report to advocate for the highest standards for oil spill prevention, response and environmental safeguards in Prince William Sound and for the people who live and work in the region affected by the Valdez Marine Terminal and tanker operations. We all share the responsibility to prevent complacency – a false sense of security on the part of industry, government, and the citizens. We believe this report demonstrates that the oil industry in Alaska can easily afford state-of-the-art environmental safeguards in Prince William Sound and still enjoy competitive rates of return on its North Slope operations. We would also like to ensure the readers that the PWSRCAC will continue its efforts to ensure that the transportation of oil through Prince William Sound is the safest anywhere in the world.

The Profitability and Economic Viability of Alaska North Slope and Associated Pipeline Operations

Prepared for the Prince William Sound Regional Citizens' Advisory Council

by

Richard A. Fineberg / Research Associates

April 27, 2005

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Acknowledgments

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Executive Summary

Despite high oil prices, some observers believe that continued aggressive petroleum development on Alaska's North Slope is not assured. Based on government documents, company reports, other trade publications, press reports and interviews with state analysts, industry experts and tax specialists, this report uses two principal modes of analysis to summarize public information on the profitability and economic viability of North Slope operations, including the associated pipelines systems: (1) long-term financial analysis, utilizing standard industry economic measurements such as rate of return, profitability ratios and net present value; and (2) estimation of the annual revenue North Slope operations and the associated pipelines generates for the operators, the state and the federal governments. This examination of the prospects for continued oil development on Alaska's North Slope leads to the following conclusions:

1. Economic Viability of the North Slope and TAPS

Two different types of economic analysis confirm that Alaska North Slope (ANS) petroleum operations and the Trans-Alaska Pipeline System (TAPS), despite reduced production during the last two decades, combine to form a business venture that continues to be profitable to investors and competitive in the international arena.

(a) Independent industry and corporate financial reports indicate that the North Slope continues to be competitive with other petroleum provinces. In a review of the operations of approximately sixty international petroleum provinces, the international consulting firm Wood Mackenzie found that despite its relatively high costs (including pipeline operations), Alaska ranks in the top quartile in terms of value per barrel to the industry, while terms offered by government generally ranks in the top half from a company perspective. (See Section II.B.) This view is confirmed by data on Alaska operation in the annual report of the only major North Slope producer that publishes Alaska-specific data. ConocoPhillips anticipates a better return on past Alaska exploration and development investment than it will earn on similar investments elsewhere in the world. (See Section II.C.)

(b) Analysis of net revenue take from North Slope production and associated pipeline operations (the difference between the price received for a barrel of oil and the costs to produce and deliver that barrel of oil to the refinery) confirms the profitability of these operations. Among the results of this analysis:

- When ANS averaged $38.84 per barrel in 2004, the industry net revenue take on North Slope production and associated pipeline operations (including TAPS) was approximately $15.0 million per day in nominal dollars (unadjusted for inflation), or 53.8% of the total net revenue take. By comparison, the state received $7.7 million (27.6%) and federal take was $5.2 million (18.6%).

- Between 1996 and 2004, industry retained more than half of the net revenue take – 54.1%, compared to 32.6% received by the state of Alaska and 13.4% by the federal government. If oil prices remain at or near $40.00 per barrel through 2005, the industry will retain more than half of the net revenue take from North Slope and associated pipeline operations for the eighth time in the past 10 years.

- The model used in this analysis indicates that the industry will earn approximately $14.8 million per day at an average price of $40.00 per barrel in 2005; when prices are at $50.00 per barrel, the industry net revenue take increases to approximately $15.5 million per day.

- When oil prices averaged $12.55 per barrel (nominal) in 1998, industry profits on North Slope production and pipeline operations were $2.3 million per day ($2.6 million per day at $14.33 per barrel in 2005 dollars). The fact that the North Slope remains profitable at low prices sets this enterprise apart, as a business concern, from national profit leaders such as IBM, General Motors and Ford, which lose money in bad years.

- This analysis indicates that the operators of the North Slope oil fields and the TAPS take a significantly larger share of the take than indicated by a similar analysis by the Alaska Department of Revenue (ADOR), primarily due to the use of estimated effective federal income tax rates instead of the nominal 35% rate used by ADOR.

The results of Alaska North Slope production and associated pipeline operations between 1996 and 2004 are summarized in the following figure:

Fig. ES.-1. Estimated Shares of Alaska N. Slope Production and Associated Pipeline Net Revenue, 1996 - 2004

Nominal Dollars

	1996	1997	1998	1999	2000	2001	2002	2003	2004	Totals
ANS West Coast Average Price ($/bbl.)	$20.44	$18.98	$12.55	$17.73	$28.28	$23.21	$24.72	$29.64	$38.84	$23.82
Total Production and P/L Net Revenue ($ Millions)	7,590.7	6,098.6	2,441.1	4,088.1	7,513.0	5,308.4	5,782.4	7,447.5	10,168.2	56,438.1
Total State Share (Production + P/L)	2,216.4	1,949.7	1,406.6	1,697.9	2,137.1	1,912.5	1,933.4	2,264.8	2,804.8	18,323.3
State Percentage	*29.2%*	*32.0%*	*57.6%*	*41.5%*	*28.4%*	*36.0%*	*33.4%*	*30.4%*	*27.6%*	*32.5%*
Federal Revenue	1,113.8	707.0	209.0	471.3	1,376.0	602.1	363.2	813.7	1,894.2	7,550.2
Federal Percentage	*14.7%*	*11.6%*	*8.6%*	*11.5%*	*18.3%*	*11.3%*	*6.3%*	*10.9%*	*18.6%*	*13.4%*
Total Industry Profits (Production + P/L)	4,260.6	3,441.9	825.4	1,918.9	3,999.9	2,793.8	3,485.8	4,369.0	5,469.2	30,564.5
Industry Percentage	*56.1%*	*56.4%*	*33.8%*	*46.9%*	*53.2%*	*52.6%*	*60.3%*	*58.7%*	*53.8%*	*54.2%*

Real (2005) Dollars

	1996	1997	1998	1999	2000	2001	2002	2003	2004	Totals
ANS West Coast Average Price ($/bbl.)	$24.03	$21.93	$14.33	$19.98	$31.24	$25.04	$26.19	$30.84	$39.63	$25.91
Total Production and P/L Net Revenue ($ Millions)	8,923.9	7,046.6	2,786.8	4,606.5	8,298.1	5,728.0	6,125.7	7,750.0	10,374.8	61,640.4
State Share (Production + P/L)	2,605.6	2,252.8	1,605.8	1,913.2	2,360.5	2,063.7	2,048.2	2,356.8	2,861.8	20,068.4
State Percentage	*29.2%*	*32.0%*	*57.6%*	*41.5%*	*28.4%*	*36.0%*	*33.4%*	*30.4%*	*27.6%*	*32.6%*
Federal Revenue	1,309.4	816.9	238.6	531.1	1,519.7	649.7	384.7	846.8	1,932.7	8,229.6
Federal Percentage	*14.7%*	*11.6%*	*8.6%*	*11.5%*	*18.3%*	*11.3%*	*6.3%*	*10.9%*	*18.6%*	*13.4%*
Industry Profits (Production + P/L)	5,008.8	3,976.9	942.3	2,162.3	4,417.9	3,014.6	3,692.8	4,546.4	5,580.3	33,342.4
Industry Percentage	*56.1%*	*56.4%*	*33.8%*	*46.9%*	*53.2%*	*52.6%*	*60.3%*	*58.7%*	*53.8%*	*54.1%*

Notes:

Based on reported spot market price for Alaska North Slpe crude oil, actual state revenue as reported by the Alaska Department of Revenue and estimated effective tax rates from Citizens for Tax Justice / Institute on Taxation and Economic Policy reports. Annual results converted to 2005 dollars using the GDP deflator.

(From Figures III.-13 and III.-14; see discussion in text.)

2. Better Public Data Are Needed

Confusion about how Alaska's petroleum fiscal regime stacks up against the terms offered by the host governments of other petroleum provinces and the difficulties acquiring the data necessary to conduct the analysis of Alaska's net revenue take demonstrate that better public information is needed to improve public understanding of Alaska North Slope petroleum operations and the intricate relationships between industry and government regulators, including revenue collectors. Recommendations for addressing this condition are made in Section IV.

Acronym List

ADOR	Alaska Department of Revenue
ANS	Alaska North Slope (crude oil)
AOGA	Alaska Oil and Gas Association
ARCO	Atlantic Richfield Co.
Boe	Barrels of oil equivalent
BP	British Petroleum
CTJ / ITEP	Citizens for Tax Justice / Institute on Taxation and Economic Policy
DD&A	Depletion, Depreciation and Amortization
DR&R	Dismantling, Removal and Restoration (pipeline tariff element)
ELF	Economic Limit Factor (severance tax factor)
E&P	Exploration and Production
FERC	Federal Energy Regulatory Commission
IRR	Internal Rate of Return
mmboe	Million barrels of oil equivalent
MSR	Maximum Sustainable Risk
NPV	Net Present Value
PWSRCAC	Prince William Sound Regional Citizens' Advisory Council
RCA	Regulatory Commission of Alaska
RDC	Resource Development Council
TAPS	Trans-Alaska Pipeline System
TRR	Total Revenue Requirement (for pipeline tariffs)
VMT	Valdez Marine Terminal (part of TAPS)
WTI	West Texas Intermediate (crude oil)

The Profitability and Economic Viability of Alaska North Slope and Associated Pipeline Operations

I. INTRODUCTION

The planning, operation and management of the Trans-Alaska Pipeline (TAPS) and its Valdez Marine Terminal (VMT) have direct and significant effects on the environment and the well-being of the people of Prince William Sound and the surrounding region. Company business decisions are inevitably influenced, if not driven, by financial considerations. Therefore, better understanding of the economics of the extraordinary business venture of which TAPS is a part should facilitate more constructive interaction with the those who make, manage and implement those decisions. The three major oil companies that own 95% of the production rights to the oil pumped from the North Slope pipeline own a roughly similar percentage of TAPS.[1] The pipeline would not exist without the North Slope and the producers could not get their oil to market without TAPS. Therefore, analysis of the economic factors relevant to business decisions regarding TAPS and the VMT inevitably lead back to the North Slope and the tightly-controlled production, transportation, refining and marketing system of which TAPS and the VMT are key components.

Apart from its role as a transportation system and as the funding vehicle for the operation of the VMT, TAPS is critical to the economic picture of North Slope

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[1] Mergers and acquisitions have changed the corporate names of the three dominant companies on Alaska's North Slope.

When Atlantic Richfield (ARCO) discovered oil at Prudhoe Bay in 1968, Exxon (then the Standard Oil Company of New Jersey) held a 50% stake in that exploration venture. Today, ExxonMobil controls approximately 36% of Prudhoe Bay, as well as major interests in nearby developments and a 20.3% stake in the Trans-Alaska Pipeline System. (See: ExxonMobil Corporation, "Companies Announce Agreement for North Slope Production" [News Release], April 13, 2000 [Prudhoe Bay]); Alyeska Pipeline Service Co., *Trans Alaska Pipeline System FACTS,* June 2003, p. 7 [TAPS]), BP, "Prudhoe Bay and Beyond" [Brochure], 1999 [other fields]).

BP's U.S. subsidiary merged with the Standard Oil Company of Ohio (Sohio) in 1970 and formally took over management of its Alaska partner in 1987 (BP Alaska Inc., *North Slope Alaska: Man and the Wilderness,* pp. 22-23). Today BP controls approximately 30% of the North Slope production and 46.9% of TAPS.

ConocoPhillips is the third major North Slope player by virtue of Phillips Petroleum's acquisition of ARCO's Alaska properties in 2000. (BP was required to divest those properties as a condition of its global merger with ARCO.) Phillips subsequently merged with Conoco, which had previously held smaller interests on the North Slope before trading them to BP and leaving Alaska in 1993. Today ConocoPhillips controls about 40% of North Slope production and owns 28.3% of TAPS.

petroleum development. To its major owners, TAPS represents both a profit center and a cost. To the non-owner shippers on TAPS – and to the state of Alaska – pipeline tariffs represent a pure cost, with negative effects. The tasks of sorting out the effects of TAPS operations on ongoing North Slope development are critical to this analysis. But these issues are difficult to analyze, in part due to the complexity of the ratemaking, accounting and tax-collecting arrangements and in part due to confidentiality strictures that make it difficult to obtain useful data. Tax consequences are intricate, obscure and important.

The industry's interest in the economic viability of the North Slope and its associated pipelines is shared by the state and federal governments. As the manager of Alaska's resource on behalf of its people, Alaska collects petroleum revenues from North Slope and TAPS operations. After the state garners its share, the federal Internal Revenue Service collects corporate income taxes from the industry.

Throughout much of 2004 and early 2005, the high price of oil made headlines. During the last week of April 2005, for example, each of the North Slope's three largest producers reported increases in first-quarter earnings. BP beat the expectations of analysts with a 29 percent increase over first quarter profits in 2004, ConocoPhillips reported that first-quarter profits soared on high oil prices, while ExxonMobil was 44% ahead of its performance in 2004, when it topped the *Fortune* "500" the largest profit ever recorded by a U.S. company.[2] Although none of these reports mentioned Alaska, approximately 10 percent of these revenues came from the North Slope and TAPS. In March 2005, a barrel of Alaska North Slope crude oil (ANS) that sold for less than $20.00 per barrel in December 2001 brought the producers two and one-half times that amount.[3] At $50.00 per barrel, the companies that delivered approximately 0.993 million barrels per day (bpd) from Alaska's North Slope in March 2005[4] were producing, handling and shipping a commodity worth nearly $50.0 million per day through the Valdez Marine Terminal (VMT). The additional $30.00 received per barrel, compared to December 2001, resulted from market forces that bore little or no relationship to the costs of producing, handling and shipping that oil. As a result of that $30.00 per barrel price windfall, during March 2005 the North Slope

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[2] Reuters (via CNN), "BP profits up 29 pct on oil prices," April 26, 2005 (http://edition.cnn.com/2005/BUSINESS/04/26/bp.results.reut/);
Associated Press (via *Forbes*), "ConocoPhillips Profit Soars on Oil Prices," April 27, 2005 (http://www.usatoday.com/money/companies/earnings/2005-04-28-exxonmobil_x.htm)**;** and "Fortune 500 lists 12 in area," *Cincinnati Enquirer*, April 5, 2005 (accessed April 5, 2005 at http://news.enquirer.com/apps/pbcs.dll/article?AID=/20050405/BIZ/504050324).

[3] In March 2005 Alaska North Slope crude oil averaged $50.63 per barrel on the West Coast spot (short-term) oil market (Alaska Department of Revenue, "Oil Price Archives," at http://www.tax.state.ak.us/programs/oil/prices/index.asp).

[4] For current ANS production figures, see: Alaska Department of Revenue, "March 2005 Highlights," at http://www.tax.state.ak.us/programs/oil/production/monthlydata/2005/Mar05.htm).

producers and the owners of TAPS were taking in an additional $29.8 million in revenue per day – a windfall with little or no increase in costs.

Despite strong earnings and a surfeit of cash from North Slope operations and TAPS, some observers believe that continued aggressive petroleum development on Alaska's North Slope is not assured. The Alaska Resource Development Council's January 2005 *Resource Review* asked, "Is Alaska A Good Place to Invest?" The council concluded that Alaska is not well positioned to compete globally for capital investment.[5]

The apparent conflict between the revenue generated from North Slope oil and the RDC's pessimistic view reflects the fact that oil development is a costly business, especially in the Arctic. Moreover, critical decisions are made in a competitive world where continued high oil prices are not guaranteed.[6] In 1988 and again in 1998, oil prices fell below $10.00 per barrel. Moreover, the days when the super-giant Prudhoe Bay and its giant neighbor Kuparuk produced 1.8 million barrels per day with ease were long gone. In 2005, those two fields still anchor North Slope development with more oil than any two fields in the country, but producing at less than one-third of their peak levels. Although billions of barrels of oil remain to be recovered from these aging North Slope fields, that oil now must be coaxed from the ground, and as fields age they produce more water and sediments; coping with these problems takes more money. In 2005, nearly half of today's North Slope production comes from smaller fields that are even more costly to develop, and production from satellites and other new fields will continue to increase. The huge heavy oil deposits near Prudhoe Bay constitute a significant portion of that increase; although these development costs have declined significantly, heavy oil remains more costly to extract than conventional deposits.

The central purpose of this report is to gather and distill public information into summary form that will shed light on these complicated questions. To clarify the economic results of the critical interactions and events critical to North Slope development, this report examines the way in which the price of a barrel of ANS

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[5] Resource Development Council, *Resource Review*, January 2005, p. 1 (http://www.akrdc.org/newsletters/2005/january.pdf). The article followed the theme of council's annual meeting. "Without progress on costs, Alaska may lose investment dollars to other less expensive regions around the world," council Executive Director Tadd Owens warned in an editorial (p. 3).

[6] The Alaska Department of Revenue forecasts that the price of Alaska North Slope crude oil will decline to a long-term price of $25.50 per barrel in nominal dollars in the next three years; if that price is maintained through 2015, by that year it would equate to $19.73 per barrel in inflation-adjusted (2005) dollars (Alaska Department of Revenue, "Historical and Projected Crude Oil Prices," *Spring 2005 Revenue Sources Book,* p. 85). The U.S. Energy Information Administration's long-term reference case average price between 2005 and 2025 is approximately $28.00 per barrel (from: U.S. Energy Information Administration, *Annual Energy Outlook 2005,* Table 11).

is converted into money to pay for prior investment, current operations, current exploration and development and – last, but certainly not least – the division of the remainder. The latter portion, frequently referred to as the net revenue take, is split among three parties: the industry, the state of Alaska and the federal government. The total paid to state and federal governments is sometimes referred to as the government take.[7]

This report uses two principal modes of analysis to summarize public information on the profitability of North Slope operations, including the associated pipelines systems. Section II views the North Slope and associated pipeline take through the lens of long-term financial analysis, which employs standard industry economic measurements such as rate of return, profitability ratios and net present value. In Section III, a simpler reckoning is attempted, based on an estimation of the annual revenue from North Slope operations and the associated pipelines and the division of that revenue among the industry, state and federal governments.

A cloak of confidentiality that shields much of the key information from public scrutiny works against the achievement of the fundamental purpose of this report. Moreover, much of the information that is available to the public is compiled in a manner that does not lend itself readily to analysis. To address this situation, this report also seeks to identify information important to public understanding of North Slope development issues that can be compiled and released to enhance public understanding without jeopardizing taxpayer confidentiality or competitive positions.

Conclusions concerning the profitability and economic viability of North Slope oil development and associated pipeline systems and recommendations regarding data acquisition and release are presented in Section IV.

[7] The state take includes oil and gas property taxes collected by the state for distribution to municipalities. The Colville River Unit, the only producing North Slope development with private interests, splits royalties among federal, state and Native interests. For a summary description of the basic components of the state's petroleum revenue system, see: Alaska Department of Revenue Tax Division, *Revenue Sources Book: Forecast and Historical Data,* Spring 2005, pp. 19-32 ("Oil Revenue").

II. LONG-TERM FINANCIAL ANALYSIS

A. Introduction

In 2004, ExxonMobil Corporation – one of the three major oil companies that control about 95 percent of the North Slope's petroleum production and a similar share of the Trans-Alaska Pipeline System (TAPS) – broke the all-time record for corporate profits, leading the *Fortune* "500" list of the nation's largest corporations in that category for the second year in a row.[8] During 2004, Alaska North Slope crude oil (ANS) averaged approximately $38.84 per barrel – a price far higher than anyone might have imagined at the end of 1998, when oil prices were less than $10.00 per barrel. In March 2005, ANS averaged more than $50.00 per barrel.[9] Under these circumstances, how could anyone think that the Alaska oil and gas industry is unable to attract the investment it requires to continue to grow? For two reasons, the answer to this question is not as straightforward as it might seem. First, the North Slope is an aging petroleum province whose two major fields – Prudhoe Bay and Kuparuk – are well into the decline that is characteristic of all petroleum reservoirs, and there are many other attractive oil provinces in the world. Recognition of these facts leads to the second part of the answer, which is that oil development is an inherently risky business. Much of that risk stems from the fact that petroleum development is capital intensive, with extended periods between discovery and pay-out to investors; this uncertainty is compounded by the volatility of oil prices. That risk is reduced through diversity. ExxonMobil, for example, operates in more than 200 countries and boasts upstream operations in nearly 40 of them.[10]

To deal with the complex realities of petroleum development, financial analysts look at potential projects from a variety of economic perspectives. A brief summary of some of these basic concepts will set the stage for the discussion of the attractiveness of development on Alaska's North Slope.[11] The would-be investor may look first at the profitability ratio (the ratio between the amount the investment will return to the investor after repaying the original investment over

[8] "Fortune 500 lists 12 in area," *Cincinnati Enquirer*, April 5, 2005 (accessed April 5, 2005 at http://news.enquirer.com/apps/pbcs.dll/article?AID=/20050405/BIZ/504050324). ExxonMobil also led the "500" list in profits in 1991, 1993, 1996, 1997, 2000 and 2001.

[9] According to Alaska Department of Revenue price records, in December 1998 the West Coast spot crude oil price averaged $9.39 per barrel. Eight months later, the spot price had increased to $20.00 per barrel. Since then, the monthly average ANS spot price has been over $20.00 per barrel in 62 of the last 67 months (Alaska Department of Revenue, "Oil Price Archives," at http://www.tax.state.ak.us/programs/oil/prices/index.asp).

[10] ExxonMobil Corporation, *2003 Summary Annual Report*, 2004, pp. 2, 6.

[11] These concepts are summarized from the remarks of Dr. Pedro Van Meurs during his training course in World Fiscal Systems for Oil and Gas (Nassau, Bahamas, Nov. 15-19, 2004.

that original investment). If it takes too long to repay that amount, it might not be a wise investment. To deal with the timing issue, would-be investors frequently consider the rate of return (an annual percentage that tells the investor how fast the original investment will be repaid). For example, a $100.00 investment that pays back $200.00 in one year has a 100% rate of return. But if that payback did not come until the tenth year, the rate of return would be approximately 7%. If the original $100.00 investment earned 7% annually for ten years, in that time $100 would also have grown to approximately $200.00. Another frequently-used metric is net present value (NPV), which is the present value of the difference between total future annual net cash flows and the original investment. A key factor in determining NPV is the discount rate, or the time value the investor arbitrarily assigns to potential investments. The discount rate that makes the NPV zero is the internal rate of return (IRR). Explorers may look at potential projects in terms of maximum sustainable risk (MSR), which is quantified as the anticipated NPV plus exploration cost over the exploration cost. If one is absolutely sure that oil will be found, a low MSR is acceptable; as the anticipated chances of discovery decline, the MSR must be higher. The applicability of each of these techniques will depend on the particular circumstances. The complexity of these concepts dictates that whenever quantitative results of petroleum development are quoted, it makes sense to ask this question: "How did you calculate the numbers on which your conclusions are based?"

Before attempting to compare Alaska with other petroleum provinces, another set of complicating factors should be mentioned: There are almost as many different petroleum fiscal regimes as there are petroleum provinces. For example, some governments collect royalties while others do not; some governments seek partners in development, while others retain operating companies as service contractors. Analysts therefore might ask this question: If the fiscal system of one country were applied to development in another country, how would the change affect the industry's share of the take? The answer is typically phrased in abstract or normative terms, which may be very different from actual results. For example, a nominal 35% federal tax rate may result in collections at a very different rate.[12] With this background in mind, it is time to look at the North Slope.

B. The Wood Mackenzie Reports

In March 2004, the Alaska Oil and Gas Association (AOGA) distributed the results of a 2002 report by the international petroleum consulting firm Wood Mackenzie, which AOGA summarized as pointing to three conclusions. From the industry's perspective, AOGA said:

- Alaska was slightly above the middle of 61 oil and gas areas worldwide in terms of government take (36th out of 61);

[12] This issue will be discussed in Section III, below.

- Alaska's North Slope was the most expensive area in this worldwide study, ranking 60th out of 60; and
- Alaska's North Slope ranked 55th out of 61 in average post-take value of remaining production.[13]

According to AOGA, these results were part of "a multi-client study completed by Wood Mackenzie in September 2002 . . . to provide a global comparison of relative attractiveness for future E&P investment" and "to evaluate the impact of Government Take in each area." The AOGA summary of the report, which was presented in bullet form, contained these summary numbers:

- Total government take: 64% (federal 17% and state 47%).
- Weighted average total costs, including "operating, cost of capital, all transportation including pipeline and marine:" $12.52 / bbl.
- Average post-take value (industry after-tax profit): $0.90 / bbl.[14]

The report itself was not public and these summary numbers, widely distributed to the Legislature in Juneau, were rife with internal contradictions that inquiries to AOGA failed to resolve.

First and foremost, the public share of the net revenue split between host government and industry (frequently referred to as the government take) is the difference between the price that a barrel of oil sells for and the industry's cost to produce it, plus all payments to government. But the numbers simply didn't add up. Based on the numbers given by AOGA, the puzzle begins here:

$19.50 per barrel crude oil price (2002 $)
(12.52) costs
$6.98 total take (amount surplus to costs).[15]

The result of removing the industry share shown in the summary numbers – $0.90 per barrel – is government take of $6.08 per barrel. But if the government received 64% of the total take, as shown by AOGA in the summary numbers, the total government take would be $4.48 per barrel ($6.98 x 0.64 = $4.48), leaving approximately $2.50 for industry profit ($6.98 - $4.48 = $2.50). Put otherwise: If total take was $6.98 per barrel and industry profit portion of that take was 36%, then industry's profit should have been approximately $2.50 – not $0.90 ($6.98 x .35 = $2.50).

[13] Letter from Judith Brady (Executive Director, Alaska Oil and Gas Association) to Representative Les Gara (Alaska State House of Representatives), March 12, 2004.

[14] Alaska Oil and Gas Association, "Alaska Benchmarking Study 2002: Alaska's Global Ranking," March 2004 (attachment to letter from Judith Brady). AOGA's brochure version of this short report is attached as Appendix A of this report.

[15] The conversion of past and future costs and profits to current dollars is always a potential source of distortion. But the critical details were not available for public review. For this reason, this problem, identified by simple math, could not be resolved.

Since the only information AOGA presented was these few summary bullets, it was not possible to figure out happened to the missing $1.60 per barrel in apparent industry profit, or how these discrepant numbers crept into the AOGA summary. But that added profit would have raised Alaska from 55th (very near the bottom) in the AOGA / Wood Mackenzie global ranking to well above the midpoint.

There were at least three other significant problems with the AOGA presentation of the Wood Mackenzie numbers: First, the cost figure of $12.52 per barrel was a bit unusual, in that it included marine and transportation costs. Typically, these costs are not included with field costs, which include the costs of operating and developing the field itself. This is not an academic point: For the major North Slope producers, who own approximately 95% of the Trans-Alaska Pipeline System (TAPS) and produce a similar share of North Slope crude oil, the $12.52 per barrel cost included at least $0.80 in after-tax profits, paid by shippers in the pipeline tariff (shipping cost).[16] In keeping with the calculations above, this would increase the total industry take significantly, from approximately $2.50 per barrel to $3.30. From the industry's perspective, profits of $3.30 per barrel would put Alaska into the top 20 of the 61 countries Wood Mackenzie studied.

The price term was also problematical. According to AOGA, the Wood Mackenzie analysis was based on a crude oil marker price of $19.50 per barrel for Brent crude in 2002, increasing 2.5 percent per year. In a summary report contained few numbers, AOGA noted that between December 1990 and February 2003, ANS averaged $17.77 per barrel on the West Coast spot market, compared to an Alaska Department of Revenue (ADOR) forecast price for 2010 of $22.00.[17] AOGA's reference to the ANS historical average suggested that the Wood Mackenzie price term was appropriate for future analysis, even though in early 2004 prices were considerably higher than the $19.50 per barrel price used in the 2002 Wood Mackenzie report. But the ADOR historical average quoted by AOGA was not adjusted for inflation and therefore was not comparable to the inflation-adjusted Brent price used by Wood Mackenzie; after correcting for inflation, the historical average price of ANS was about $5.00 per barrel higher – and the ADOR forecast price about $4.00 lower – than AOGA indicated.[18] Moreover, in publishing this information in January 2004, AOGA might have updated its information with the more recent Fall 2003 forecast, which would

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[16] Based on TAPS tariff filings, the Alaska Department of Revenue (ADOR) estimated 2001 TAPS profits at $299.6 million; assuming shipments of 362.8 million barrels (estimated total production for that year), the total tariff profit allowance would be approximately $0.83 per barrel (see Figures III.-1, III.-4 and III.-8, below). (Note: This estimate of TAPS profits is a conservative reckoning; TAPS tariffs issues will be discussed in greater detail below and in Section III.)

[17] "Alaska Benchmarking Study 2002: Alaska's Global Ranking," p. 4.(Historically, the reported Brent price is comparable to that of ANS.)

[18] See: Alaska Department of Revenue, "Historical and Projected Crude Oil Prices," in *Revenue Sources Book: Forecast & Historical Data*, Spring 2003, p. A4.

have included the full fiscal year 2003 (when oil prices averaged $28.15/bbl.) and the first half of the next fiscal year (when oil prices were over $30.00/bbl).[19]

Substantive details about the 2002 Wood Mackenzie report that would help the general reader understand the meaning of the few pieces of summary data released by AOGA did not come to light for nearly a year. But, as shown above, simple math demonstrated the need for closer examination of the methods and the data on which the AOGA conclusions were based. In the meantime, members of the general public interested in oil and gas public policy issues were left to grapple with a report whose conclusions, as summarized by AOGA, were, at best, internally inconsistent and subject to erroneous interpretation.

In December 2004, for example, confusion about North Slope development economics surfaced once more, when a new AOGA report estimated that Alaska would need investment of approximately $60.0 billion in the next decade to hold North Slope oil production at 1.0 million barrels per day (bpd), or 3.65 billion barrels of oil.[20] AOGA cited reports by the Alaska Department of Revenue (ADOR) Tax Division as the source for this estimate, but ADOR personnel did not accept the AOGA conclusions. Dan Dickinson, director of the ADOR Tax Division, said his unit estimated new investment of $14.0 billion, coupled with ongoing production costs of $2.0 billion per year, might be required to produce a forecast average of about 0.9 million bpd. That would add up to $34.0 billion. Dickinson noted that even adding $5.0 billion to increase production to reach the 1.0 million bpd level would raise the ADOR estimate to $40.0 billion at the outside. In other words, the industry organization was projecting future total costs for North Slope production in excess of $16.00 per barrel ($60.0 billion / 3.65 billion barrels = $16.44), while the state estimated per-barrel cost on the order of $11.00. Dickinson pointed out that both cost estimates included major production from existing infrastructure at Prudhoe Bay and Kuparuk, whose additional production will not cost as much, on a per-barrel basis, as initial development of new, smaller fields.[21] Amidst the confusion over the basic numbers, important policy questions went unasked and unanswered: How many additional health, safety and environmental expenditures, amortized over billions of barrels and tens of years, would it take to have any significant effect on the long-term economic viability of the North Slope development?

AOGA and ADOR both claimed their estimates were consistent with Wood Mackenzie data. According to *Petroleum News*, AOGA quoted the summary

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[19] See: Alaska Department of Revenue, “Historical and Projected Crude Oil Prices,” in *Revenue Sources Book: Forecast & Historical Data*, December 2003, p. A4.

[20] Kay Cashman, “Alaska needs $60B to bridge gap to gas pipeline,” *Petroleum News*, Dec. 5, 2004, p. 12. (The new AOGA report figured prominently in the Resource Development Council’s gloomy January 2005 assessment of Alaska’s development prospects discussed in Section I.)

[21] Kristen Nelson and Kay Cashman, “State of Alaska, AOGA differ on $60B estimate,” *Petroleum News,* Dec. 12, 2004, p. 4.

numbers from the 2002 report, while ADOR said its numbers were consistent with a recently completed update to the 2002 Wood Mackenzie report.[22] Once again, however, the 2004 Wood Mackenzie report was not available to the public. The Alaska State Legislature spent approximately $50,000.00 to obtain a report that only legislators and specially appointed designees could see. And no legislator could see the report without signing a strict confidentiality agreement; Wood Mackenzie was so concerned about keeping its work product from non-paying eyes that legislators were warned that if they disclosed information from the report they might face legal action with severe financial penalties under British law (Wood Mackenzie is based in Scotland).[23]

On Feb. 1, 2005, Senator Gene Therriault (R-North Pole), Chairman of the Legislative Budget and Audit Committee, released two pages of summary data from the new Wood Mackenzie report. Again the summary data were cryptic in the absence of supporting information, but the few numbers that were released made it clear that the new version of the Wood Mackenzie study painted a very different picture from that of the AOGA summary of the earlier study. From the industry's perspective Alaska had risen to well above average in the percentage of the total take to producers. Alaska, ranked 36th on the list released in 2002, rose to a ranking between 17th and 8th in 2004, depending on the price of oil. On a per-barrel basis, industry profits were estimated at $2.14 per barrel (at a base price of $22.00 per barrel), with a range from $0.90 per barrel (at $16.00 per barrel) to $4.43 (at $35.00). Moreover, Alaska's reported costs dropped by more than $2.60 per barrel (Alaska was now ranked 52nd out of 58, up from dead last in the prior study).[24]

What caused the changes in Alaska's rankings? Which report offered a more correct picture of Alaska's status? Working from two pages of numbers purporting to summarize a confidential report said to be two inches thick, it was difficult to tell. Even informed officials professed some confusion. "What I can't figure out is whether Wood Mackenzie may have limited the (2004) study to more recent oil fields," ADOR's Dickinson told *Petroleum News*.[25] AOGA Executive Director Judy Brady said she was surprised by the apparent disparity between the two studies and immediately directed follow-up questions to Wood

[22] "State of Alaska, AOGA differ on $60B estimate."

[23] Larry Persily, "Report on oil, gas is top secret: 'Under Lock and Key:' Company that did study could seek fine if it's revealed," *Anchorage Daily News*, Jan. 12, 2005.

[24] Alaska State Legislature, "Details from Study on Alaska Oil Industry are Released," Feb. 1, 2005 ("News from the House & Senate Majority"). The summary data can be found at Appendix B of this report.

[25] Rose Ragsdale, "Wood Mackenzie: Alaska costly, but profitable: Lawmakers offer public glimpse of state's ranking among world's oil patches; 24% profitability at $22 per barrel," *Petroleum News,* Feb. 6, 2005, p. 9.

Mackenzie.[26] In releasing summary information, the Legislative Budget and Audit Committee announced that it was hiring another analyst to review the study and return to the Legislature with another analysis of the secret, $50,000.00 report.[27]

In mid-February 2005, Wood Mackenzie responded to the confusion about Alaska's position in the global oil patch with a press release that explained the differences between the two reports and the effects of those differences on the results for Alaska. According to the consulting firm, its 2004 study "enhances a similar study conducted by Wood Mackenzie in 2002 but, while some aspects are comparable, others are very different."[28] The Wood Mackenzie press release placed the numbers released by the Legislature two weeks earlier in context by highlighting the following "key points" from its still secret report:

- Field Costs: "Alaska has relatively high field costs (capital and operating) ranking 52nd of the 58 areas that made discoveries between 1994 and 2003." Those costs were reported as $9.95 per barrel, down from $12.52 in the 2002 report.
- Exploration Activity: "Alaska ranks in the top quartile in terms of average discovery size . . . and in the top half in terms of commercial success rate . . . and reserves discovered . . . . These results and Alaska's ranking position are comparable to the . . . 2002 results."
- Government Take: [Government take in both studies] "is calculated as between 55% and 72% of the Pre-Take Net Present Value using a 10% discount rate (NPV_{10}) . . . and generally ranks in the top half from a company perspective."
- Value per barrel: "Alaska ranks in the top quartile in terms of post-take development an Full Cycle NPV_{10} per boe [barrel of oil equivalent]. . . . These values are not directly comparable with the value of all remaining production reported in the . . . 2002 study."[29]

The Wood Mackenzie press release was accompanied by four pages of information that disclosed in greater detail the methodologies and the differences between the consulting firm's 2002 and 2004 reports. The new information shed light on some of the major mysteries associated with the release of partial data from the Wood Mackenzie reports:

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[26] Rose Ragsdale, "Profitable ranking of oil patch may be misleading: State's competitive edge may be fleeting in face of recent tax hike, price decline says AOGA's Judy Brady," *Petroleum News*, Feb. 13, 2005, p. 14.

[27] "Details from Study on Alaska Oil Industry are Released."

[28] Wood McKenzie, "Wood Mackenzie's Global Oil and Gas Risks and Rewards Study 2004" (press release), Feb. 16, 2005. The Wood Mackenzie materials are attached to this report at Appendix C.

[29] "Wood Mackenzie's Global Oil and Gas Risks and Rewards Study 2004," p. 1.

- If one looks at remaining value for the fields analyzed in the 2004 study (instead of estimating full-cycle or life of field average profits) Wood Mackenzie's estimated industry base price profit figure of $2.14 per barrel rises to $3.06; these figures apparently differ from the 2002 report estimates because different fields were studied.

- According to Wood Mackenzie, the 2002 report estimate of $0.90 per barrel industry take cited by AOGA is not comparable to the field cost estimates from the same report. The 2002 profit figure, Wood Mackenzie explained, looked at remaining value from all fields in production at the time and therefore was "dominated by Prudhoe Bay economics (including gas)," where, among other things, delayed production prospects for the huge deposits of Prudhoe Bay natural gas significantly reduced the estimated NPV. But when it came to computing production costs, Wood Mackenzie looked only at fields under development since 1995. Therefore, the older fields – including Prudhoe Bay and Kuparuk – were excluded from the production cost analysis. The result was that the data were not comparable.[30] One industry observer suggested that the Wood Mackenzie 2002 profitability estimate was further diminished by the fact that several of the fields in that group experienced development delays that reduced their NPV.[31] In sum, the $0.90 per barrel industry take figure cited by AOGA – identified from simple math above as inconsistent with other report data – cannot be regarded as an accurate representation of the industry's take from North Slope operations.

- Wood Mackenzie disclosed that a major cause of the reduced 2004 production cost estimate was that marine transportation costs, included in the 2002 analysis, were excluded in 2004.[32] In the 2004 study's cost analysis (unlike the profit calculations), Prudhoe Bay gas did not play a role. By the same token, the 2002 study focus on remaining value deprived the Alaska results of the benefit of the lower production costs associated with the early days of North Slope field development.

- From the data Wood Mackenzie presented, it was still not clear how pipeline costs were calculated. A critical question in this regard is whether Wood Mackenzie recognized TAPS profit elements and added

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[30] The 2004 report dealt exclusively with discoveries since 1994, considering both past and future production ("full life-cycle") at a range of future prices. Thus, the economics of major portions of North Slope production were not considered. ("Wood Mackenzie's Global Oil and Gas Risk and Rewards Study 2004," attachments, pp. 5, 6.)

[31] See: "Profitable ranking of oil patch may be misleading: State's competitive edge may be fleeting in face of recent tax hike, price decline says AOGA's Judy Brady."

[32] "Wood Mackenzie's Global Oil and Gas Risk and Rewards Study 2004," attachments, p. 5.

them to the profit column before estimating the take on Alaska operations. As noted above, this addition would result in a significant increase to the industry share of the total net revenue take.

This review of the available information regarding the two Wood Mackenzie reports shows the importance of the simple question asked at the start of this section: "How did you calculate the numbers on which your conclusions are based?" In any event, this review of the summary data now on the public record from the Wood Mackenzie reports suggest that Alaska's North Slope continues to be economically viable and competitive in the international arena.

C. ConocoPhillips Annual Reports

Analysis of ConocoPhillips annual reports provides corroboration for the preceding conclusions regarding the Wood Mackenzie reports. In their annual reports, companies that produce oil and gas must provide an annual summary of specific aspects of that business in accordance with guidelines established by the Financial Accounting Standards Board.[33] In compliance with this requirement, the ConocoPhillips annual report includes a section with statistics on oil and gas operations, and in this portion ConocoPhillips has isolated its Alaska results from those of its principal oil and gas operations in other regions.[34] One of the required items is a standardized measure of discounted future net cash flows from producing the company's proved oil and gas reserves. In this analysis, ConocoPhillips has applied year-end market prices, costs, statutory tax rates (less allowable deductions), and a discount factor of 10 percent to year-end quantities of net proved reserves. These amounts represent ConocoPhillips' best estimates, using standardized reporting requirements, of the difference between the amounts that the company has spent to develop, produce and transport proved reserves and the estimated amounts it will receive annually from production of those reserves. From the report data, the reason that ConocoPhillips has singled out Alaska is immediately apparent: Future cash inflows and discounted future net cash flows from Alaska are both significantly larger than for any other province where ConocoPhillips operates.[35] Figure II.-1,

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[33] Financial Accounting Standards Board, "Summary of Statement No. 69 (Disclosures about Oil and Gas Producing Activities – an amendment of FASB Statements 19, 25, 33, and 39 (Issued 11/82)," accessed March 26, 2005 at http://www.fasb.org/st/summary/stsum69.shtml.

[34] Neither ExxonMobil nor BP publish comparable Alaska-specific information that can be analyzed in this manner. (Alaska represents a significant but much smaller portion of total oil and gas operations for both companies, while BP, a British firm, has different reporting requirements.)

[35] From production data in the statistics section of the ConocoPhillips report, it may be inferred that at least 90 percent of the company's Alaska production revenues are derived from the North Slope.

below, compares the company estimate of discounted future net cash flows from Alaska to those anticipated from other major producing regions.[36]

Figure II.-1. ConocoPhillips Discounted Future Net Cash Flows Relating to Proved Reserves at Year-end 2003

($ Millions – at 10% annual discount)

	Alaska	Lower 48	European North Sea	Asia Pacific	Canada	Other Areas
Discounted Future Net Cash Flows	$9,488	$7,656	$6,488	$4,799	$2,235	$396

Source: *ConocoPhillips 2003 Annual Report*, p. 106.

As noted at the start of this section, the magnitude of net cash flows is not the only criterion for evaluating economic performance. From other statistics in the annual report data, it is also possible to estimate profitability ratios for each of the listed areas; this is done by comparing the discounted future net cash flows (which include anticipated future costs) to the costs incurred in developing those reserves to date.[37] Figure II.-2 presents those results by region, and for the entire company. This figure indicates that for every dollar invested in proved reserves – the lifeblood of any oil company – ConocoPhillips expects to earn, company-wide, approximately $1.20. But on its Alaska investment, ConocoPhillips expects to earn more than $1.40 per invested dollar.

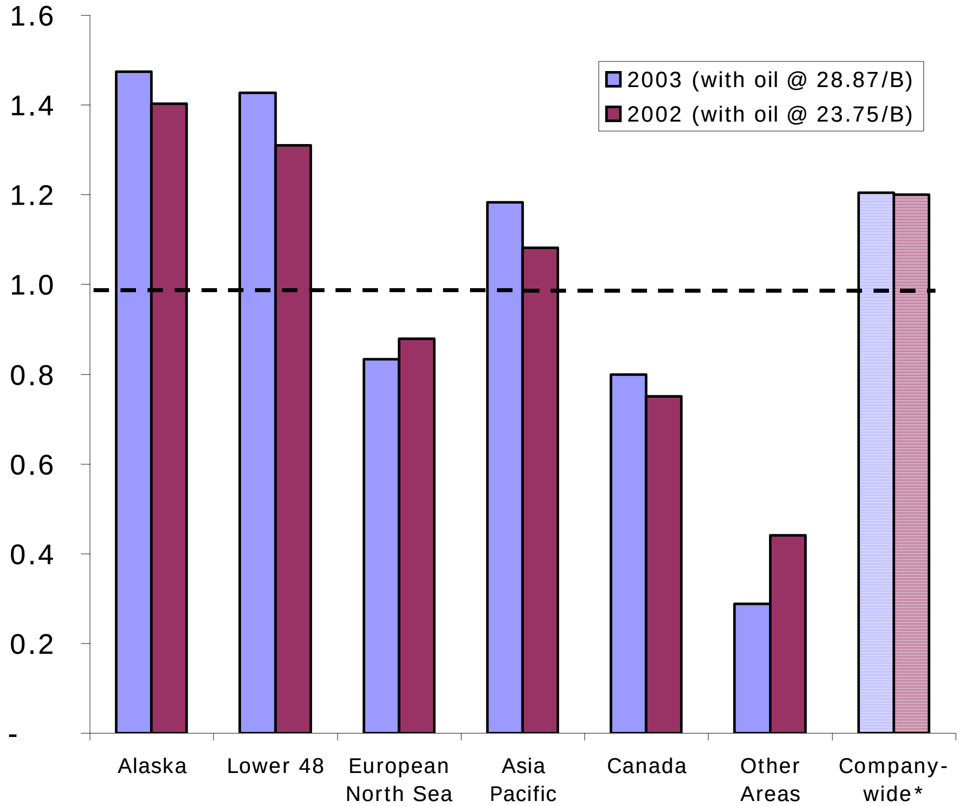
In other words, ConocoPhillips expects that Alaska operations will deliver returns on continuing operations, relative to past investments, superior to those of the company's other principal production areas. While it is clear that the industry benefits from high oil prices, it is interesting to note that Alaska also outperformed other regions in 2002, when ConocoPhillips reported receiving approximately $23.75 per barrel, as well as in 2003, when prices rose more than 20%, to $28.87. Thus, Alaska's superior performance may be associated with factors other than high prices – for example, favorable geology and fiscal system.

[36] *ConocoPhillips 2003 Annual Report,* p. 106 ("Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities") and *ConocoPhillips 2002 Annual Report,* p. 102 ("Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities").

[37] Capitalized costs are presented by region in a separate table of that title in the statistics section of the *ConocoPhillips 2003 Annual Report* at p. 105.

Figure II.-2. ConocoPhillips Profitability by Region

(NPV of future production at 10% discount)/(Capitalized Costs)



Source: *ConocoPhillips 2003 Annual Report* pp. 105, 106. * Includes minority interests not included in regional data.

According to the *ConocoPhillips 2003 Annual Report*, the Alaska NPV and profitability figures shown, respectively, in Figures II.-1 and II.-2 relate only to the company's exploration and production (E&P) segment and do not include profits from the pipelines associated with those operations.[38] As noted earlier, the TAPS owners – including ConocoPhillips, the second largest owner of TAPS with a 28% interest – collect more than $0.80 per barrel in recognized profits through the pipeline tariff, adding significantly to the industry share of the net revenue take from Alaska operations.[39]

[38] "Results of operations for producing activities consist of all the activities within the E&P organization, except for pipeline and marine operations . . . ." (*ConocoPhillips 2002 Annual Report*, p. 99; *ConocoPhillips 2003 Annual Report*, p. 101.).

[39] See discussion above at page 12 (footnote 16), above.

D. The Trans-Alaska Pipeline System: Boon or Bane?

The transportation costs that set Alaska apart may in fact be a plus for the major North Slope developers. In addition to contributing directly to the industry net revenue stream, profits on TAPS function to reduce risk – and state royalty and severance tax payments.[40] These relationships and the following information combine to heighten interest in the analysis of TAPS tariffs, the total net revenue take and the division of that take:

- After a five-year review of TAPS tariffs, in 2002 the Regulatory Commission of Alaska (RCA)[41] concluded that the TAPS Owners had collected an excess of more than $9.9 billion between 1977 and 1996, and that current tariffs were excessive. While the RCA felt it did not have authority to address historical overcharges, the commission ordered reductions to the tariffs under its jurisdiction for 1997 through 2000. The filed tariffs were generally in the $3.00 per barrel range the commission ordered reductions to less than $2.00 per barrel and required refunds. In June 2004 the Commission issued a second order to the same effect for subsequent tariffs.[42]
- In response to the filing of tariffs averaging approximately $3.72 per barrel in December 2004, the State of Alaska (whose royalty and severance tax payments are reduced by excessive tariffs) and Anadarko Petroleum (an independent North Slope producer) challenged the interstate tariffs at the Federal Energy Regulatory Commission.[43]

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[40] Transportation costs – of which the TAPS tariff is the largest portion – are subtracted from the market price of a barrel of crude oil to determine the basis for state royalty and severance tax payments; these costs are also deducted before calculating state and federal income tax payments. Therefore, increased pipeline costs reduce both the state and federal take.

[41] Under AS 42.06, the RCA is responsible for assuring that pipeline tariffs charged by pipeline owners for oil shipped in intra-state commerce are just and reasonable; on TAPS, approximately five percent of total shipments are under RCA jurisdiction. The remaining 95% of TAPS shipments – the portion destined to leave Alaska – is regulated by the Federal Energy Regulatory Commission (FERC).

[42] Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues* (Order P-97-4[151] / P-97-7[110]), Nov. 26, 2002, and *Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings, Rejecting the TAPS Carriers' Post-2000 Revenue Requirement and Rate Filings, Establishing Permanent Post-2000 Intrastate TAPS Rates, Requiring Refunds, Ordering Release of Escrowed Funds, Letters of Credit, and Bonds; Approving Filings and Affirming Electronic Rulings,* June 11, 2004 (Order No. P-04-3[34]Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates* and *Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings.*

[43] State of Alaska, *Protest and Petition for Investigation into the Proposed 2005 TAS Tariffs and Complaint and Petition for Investigation into the 2003 and 2004 TAPS Tariffs by the State of Alaska and Intervention in Any Subsequent Proceedings*, *Corporation* (Federal Regulatory

- The TAPS owners retain possession of more than $1.5 billion in TAPS tariffs previously collected for dismantling, removal and restoration (DR&R) operations. The RCA's June 2004 order suggests that although the owners agreed not to collect the small remaining portion of DR&R agreed to under the 1985 TAPS Tariff Settlement Agreement, the Owners may be collecting additional tariffs for this function by including those charges as part of other tariff elements.[44]
- As noted earlier, for approximately 95% of the oil shipped on TAPS, the producer is also a major TAPS owner. Under these circumstances, pipeline shipping costs are paid by the company's production subsidiary to the transportation unit of the same company. But the remaining five percent of the oil shipped on TAPS by producers who do not own a piece of TAPS, the pipeline tariff – including the profit element – is paid out of pocket, adding to their costs while increasing the profits recorded by the TAPS owners. The importance of a stake in TAPS was summarized a decade ago by Archie Dunham, the recently retired Chairman of ConocoPhillips, when he was the Chairman and CEO of Conoco. Under Dunham, Conoco had developed the Milne Point field and was the only firm operating a field on the North Slope that did not own a portion of TAPS. In 1993, Conoco sold its North Slope interests to BP and left Alaska. Against the relatively low oil prices of 1993, the guaranteed profits from pipeline ownership might have kept Conoco's Alaska operations afloat until prices rose again.[45] Later, reflecting on his company's departure from Alaska, said, "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 Sea are so worried."[46]

Over and above these economic considerations, expenditures for health, safety and environmental protection on TAPS and at the VMT are provided through the TAPS tariff. For this reason, Alaskans and the people of the Prince William

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Energy Commission, Docket Nos. IS05-82-000, IS05-80-000, IS05-72-000, IS05-62-000 and IS05-65-000), Dec. 15, 2004; and Anadarko Petroleum Corporation, *Protest, Complaint, Motion to Intervene, Motion to Consolidate, and Request for Hearing and Other Relief of Anadarko Petroleum Corporation* (Federal Regulatory Energy Commission, Docket Nos. IS05-82-000, IS05-80-000, IS05-72-000, IS05-62-000 and IS05-65-000), Dec. 16, 2004.

[44] For an extended analysis of TAPS DR&R issues, see: Richard A. Fineberg, *Trans-Alaska Pipeline System Dismantling, Removal and Restoration (DR&R): Background Report and Recommendations* (prepared for the Prince William Sound Regional Citizens' Advisory Committee), June 24, 2004.

[45] For the effect of pipeline costs on Conoco's profitability in1993, its final year of operation in Alaska, see *How Much Is Enough?,* pp. 27-35.

[46] "Getting to the Future First," *Hart's Oil and Gas Investor,* August 1996, p. 41.

Sound region have a special need for clear understanding of the complex economic linkages between North Slope operations and TAPS. It is therefore unfortunate that critical facts about the TAPS tariff are deemed confidential by the industry and public officials. With even the most rudimentary data on the TAPS tariff cloaked in confidentiality, it is difficult for members of the public to review tariff policy decisions made on their behalf by public officials.[47]

E. Conclusions

This attempt to assess the economics of North Slope oil production and the pipeline system that transports that oil to Valdez has highlighted two principal conclusions:

- International comparisons by the Wood Mackenzie consulting firm suggest that, from an industry standpoint, Alaska ranks in the top half in discovery success and in generosity of terms and in the top 25 per cent in terms of value per barrel and size of recent discoveries.
- Data from the annual reports of ConocoPhillips, the only one of three major North Slope producers and TAPS owners that reports such information, corroborate the Wood Mackenzie results.

The following observations summarize some of the difficulties encountered in this analysis:

- Pipeline tariffs, costs and profits play an important part in North Slope development economics. Unfortunately, however, the basic facts about TAPS tariffs are not available for public review.
- Assessment of the economic viability of future investments is liable to be confounded by confusion between existing infrastructure at developed fields and new infrastructure at new fields.
- Petroleum development cost estimates are apt to vary widely, depending on the particular developments studied and assumptions and methodologies used.
- If the debate over the North Slope's future swings around the difference between the expenditure of sums on the order of $40 billion to $60 billion during the next decade, the much smaller additions to expenses associated with increased hazard mitigation measures and improved spill

[47] Although state personnel have cooperated in making information available on request, their responses are limited by confidentiality requirements, as well as by their available time and resources. For example, although detailed information on TAPS tariff calculations and the annual revenue requirements for specific elements of the tariff were available to the general public in 2001, requests to state officials for updated information on TAPS tariffs have been denied. (See Appendix E.)

> response programs on TAPS and at the VMT are unlikely to have significant effects on the economic viability of North Slope development[48].

In light of these considerations, can analysis of annual costs and profits associated with these operations provide meaningful information that will assist in assessing the continued economic viability of North Slope operations and the associated pipelines? This question is the focus of the next section.

[48] For example, a 67% increase in the Strategic Reconfiguration of TAPS – which includes the change of pump stations from manned, fuel-driven jet propulsion-powered pump stations to unmanned, electricity-powered pumping operations, major changes in the pipeline control system and the VMT storage tank and safety systems – would increase the project cost by approximately $400 million. An increase of that extraordinary magnitude would constitute only 0.67% to 1.0% of total future investment costs discussed at p. 17, above.

III. ANNUAL TAKE FROM NORTH SLOPE AND ASSOCIATED PIPELINE OPERATIONS

A. The North Slope Net Revenue Take Model

Confusion about the conclusions of the Wood Mackenzie reports and debate about the attractiveness of North Slope development opportunities demonstrate the importance of understanding how the numbers critical to petroleum analysis are derived, and what they mean. This, in turn, requires knowing two things: what was the basis for the inputs, and how were the inputs used to determine the outputs? When the critical data are held confidential, it is difficult to answer these questions with confidence. Replicating the results is liable to be difficult, if not impossible; one reason that clients pay international consultants like Wood Mackenzie is that much of the necessary information is not readily available to the general public. One way to deal with this problem is to try a simpler set of questions whose answers can be verified. Starting down this track, this section begins by asking this set of question: How much money does the industry make from the North Slope fields and transportation of that oil to tidewater at Valdez, and how does that amount compare to the state and federal take? Hopefully, this simpler approach will yield provide the reader with information that will be useful in considering petroleum development issues.

One goal of this report is to enable the general reader to understand, based on public information, how value is derived from a barrel of Alaska North Slope crude oil. To avoid the problems of data inaccessibility encountered in analyzing the Wood Mackenzie reports, a simplified model, based on public data and designed for public use, will be used. In the course of considering the model, the need for better public information on the economics of North Slope production and associated pipeline operations will become increasingly clear.

The vehicle selected for this inquiry was developed by the Alaska Department of Revenue (ADOR) to summarize the division of the net revenue take from North Slope production operations and TAPS. As discussed in the preceding section, the net revenue take is the difference between the price of a barrel of oil and the costs to produce and deliver that oil to market. Three parties share the take: the companies that produce and transport the oil to market, the state of Alaska and the federal government. The model, reproduced in Figure III.-1 on the following page, uses public information to summarize those shares; its anchor is the money the state collects annually, through its fiscal system, from North Slope production operations and TAPS.[49]

[49] Alaska Department of Revenue, “Shares of Alaska’s Oil Revenue Pie (Production and Value Added by TAPS),” worksheet in Microsoft Excel workbook, “Integrated Profit Model.” The version reproduced here was released in February 2005.

Figure III.-1. Alaska Department of Revenue North Slope Net Revenue Take Analysis (February 2005)

Shares of Alaska's Oil Revenue Pie (Production and Value Added by TAPS)

	FY 1988	FY 1989	FY 1990	FY 1991	FY 1992	FY 1993	FY 1994	FY 1995	FY 1996	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004
Note 1																	
Sales Price ($/Bbl)	$16.45	$14.80	$17.34	$21.72	$16.88	$17.93	$14.22	$16.83	$17.81	$20.85	$16.03	$12.70	$23.27	$27.85	$21.78	$28.15	$31.74
Transportation Cost to Market ($/Bbl)	$5.92	$5.44	$5.44	$6.34	$5.67	$5.13	$4.65	$5.32	$5.21	$4.45	$4.12	$4.23	$4.45	$5.61	$4.98	$4.80	4.50
Wellhead Price ($/Bbl)	$10.53	$9.36	$11.90	$15.38	$11.21	$12.80	$9.57	$11.51	$12.60	$16.40	$11.91	$8.47	$18.82	$22.24	$16.80	$23.35	$27.24
ANS Production (Million Bbl/Yr)	717.4	696.8	658.1	636.2	628.5	588.4	558.8	573.8	538.0	512.5	465.4	424.5	387.5	361.7	366.1	361.5	360.7
Production Value (Million $)	7554.4	6521.4	7828.9	9785.0	7045.8	7532.1	5347.9	6604.2	6778.9	8404.3	5542.6	3595.5	7292.5	8044.5	6150.4	8440.9	9826.1
Note 2																	
Production Costs ($/Bbl)	4.00	3.80	3.70	3.50	3.50	3.31	3.07	2.97	3.09	3.67	4.24	4.67	5.10	5.96	6.44	6.44	6.50
Production Costs (Million $)	2869.4	2647.8	2435.0	2226.7	2199.9	1947.5	1715.6	1704.1	1662.5	1880.7	1973.2	1982.4	1976.2	2154.4	2356.9	2327.3	2344.7
Note 1																	
State Revenue + Muni Oil Prop (Millions $)	2225.3	2003.5	2407.1	3077.6	2446.9	2435.5	1658.1	2019.5	2066.5	2446.6	1693.5	1223.1	2097.4	2371.1	1736.8	2227.7	2514.7
Severance Tax	818.7	698.8	1001.6	1284.8	1053.2	1017.6	692.1	793.9	787.2	921.6	577.8	371.1	702.7	703.1	496.3	599.0	651.9
Avg Economic Limit Factor (ELF)	0.792	0.785	0.938	0.926	0.926	0.927	0.917	0.905	0.883	0.839	0.812	0.742	0.680	0.639	0.593	0.552	0.5
Gross Royalty	964.4	854.5	1020.2	1336.7	964.3	1051.5	703.1	858.2	873.5	1032.0	691.3	506.1	1038.4	1134.7	861.7	1278.7	1368.0
Adjustment for Cook Inlet Revenues	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Property Tax State Share	96.2	89.7	89.8	85.0	69.0	66.9	61.5	57.3	56.0	53.6	51.3	48.5	45	45.0	49.7	48.7	47.3
Property Tax Muni Share	258.0	264.5	248.3	256.0	264.8	251.9	253.6	251.7	246.1	240.0	243.0	222.3	218.6	220.2	220.7	220.2	218.7
Total Income Tax	158.0	166.0	117.2	185.1	165.5	117.6	17.8	128.5	173.7	269.4	200.1	145.1	162.7	338.1	178.4	151.1	298.8
Income Tax Production	44.7	65.2	17.1	87.6	74.1	34.0	-59.1	57.8	111.1	217.0	156.6	105.1	123.3	297.7	136.7	109.4	257.1
Income Tax TAPS	113.3	100.8	100.1	97.5	91.4	83.6	76.9	70.7	62.6	52.4	43.5	40.0	39.4	40.4	41.7	41.7	41.7
Note 3																	
TAPS tax allowance (Millions $)	566.7	503.9	500.7	487.4	457.0	418.2	384.7	353.5	312.9	262.1	217.3	200.0	197.1	202.2	208.5	208.5	208.5
TAPS after tax margin	308.2	257.4	303.0	326.1	336.3	320.8	322.0	318.2	309.1	290.1	275.2	254.7	243.2	248.5	256.7	256.7	256.7
TAPS deferred return	558.7	515.1	463.7	419.8	363.5	296.9	245.4	203.7	153.7	81.5	49.5	48.6	50.1	51.1	51.2	51.2	51.2
Note 4																	
Federal Revenue (Millions $)	1353.9	1092.9	1481.0	1992.3	1237.3	1466.0	1025.7	1315.7	1339.7	1655.0	845.6	310.5	1298.1	1407.6	901.2	1541.5	1919.8
Percentage Federal	**22.1%**	**21.2%**	**22.2%**	**22.7%**	**20.6%**	**22.1%**	**22.4%**	**22.8%**	**22.7%**	**23.1%**	**20.6%**	**14.7%**	**22.4%**	**22.0%**	**20.9%**	**23.2%**	**24.0%**
Note 5.																	
Company Net Revenue (Millions $)	2539.3	2053.5	2773.2	3721.7	2318.6	2718.9	1900.7	2440.1	2485.9	3055.7	1572.3	582.8	2411.2	2613.3	1671.8	2860.9	3563.4
Percentage Company	**41.5%**	**39.9%**	**41.6%**	**42.3%**	**38.6%**	**41.1%**	**41.5%**	**42.3%**	**42.2%**	**42.7%**	**38.2%**	**27.5%**	**41.5%**	**40.9%**	**38.8%**	**43.2%**	**44.6%**
State Revenue + Muni Property (Millions $)	2225.3	2003.5	2407.1	3077.6	2446.9	2435.5	1658.1	2019.5	2066.5	2446.6	1693.5	1223.1	2097.4	2371.1	1736.8	2227.7	2514.7
Percentage State & Local	**36.4%**	**38.9%**	**36.1%**	**35.0%**	**40.8%**	**36.8%**	**36.2%**	**35.0%**	**35.1%**	**34.2%**	**41.2%**	**57.8%**	**36.1%**	**37.1%**	**40.3%**	**33.6%**	**31.4%**
Total Revenue Shared (State, Federal, Co.)	6118.5	5150.0	6661.3	8791.6	6002.7	6620.5	4584.4	5775.4	5892.2	7157.3	4111.4	2116.4	5806.7	6392.0	4309.9	6630.0	7997.8

Alaska Department of Revenue Notes:

1. Revenues, prices, and production taken from Fall Revenue Sources. Sales price is the average market price on the US West Coast except for prior to FY 2000 which includes Far East and Gulf Coast sales.
2. Production Cost is taken from "How Much is Enough" by Richard Fineberg for FY 1988--FY1996, Dept. of Revenue estimates for FY 1997--FY 2003.
3. TAPS tax, after tax margin, and deferred return allowances from actual filings
4. Federal Revenue is calculated as 35% of the difference between production value and production cost (including state taxes on production) plus 80% of the TAPS tax allowance. 80% is the fed rate divided by the sum of the fed and state rates. The maximum marginal fed rate is 35%, the state rate is 9.4%.
5. Company net revenue is calculated as production value less production costs less taxes on production plus the TAPS after tax allowance plus deferred return.

Additional Notes:

1. The following changes were made to ADOR FY 2004 state revenue entries to reconcile state FY 2004 totals with the department's Fall 2004 Revenue Sources (pages 3, 7, 31, 35, 83, 85, 86):

	ADOR Shares	*Rev. Sources (this figure)*
Sales Price ($/bbl.)	$31.71	$31.74
Severance Tax (Million $)	652.70	651.90
Total Municipal Property Tax (Million $) .	268.00	266.00 *
State income tax (million $)	299.00	298.80
Net Decrease in State "Take" (Million $)		3.0

** Adjusted for rounding errors.*

2. Production costs shown for FY 93-96 and 1999-2004 based on calendar-year estimates.

(Note: These data constitute a starting point for analysis and do not represent the findings or conclusions of this report.)

(Research Associates, March 2005)

The ADOR model was ingeniously designed to summarize shares of the net revenue take from North Slope production and pipeline operations for the last seventeen years on a single page. But no model can be expected to fill every need, and there is a price for simplicity and compactness. In the case of the ADOR model, five problems detract from the value of this model as a public policy vehicle.

- First, the data are arrayed in state fiscal years, which run from July 1 of the preceding calendar year to June 30 of the calendar year.[50] While fiscal year data are useful to state personnel in dealing with state fiscal issues, most analyses of oil and general economic issues are presented in terms of calendar-year data. This is true of company reports, U.S. Energy Department figures and most international data. Because the model data are organized into state fiscal years, they are difficult to compare to conventional historical arrays.[51] This problem is liable to have a significant effect on the analysis of single-year data and any projections based on those data.[52] Moreover, the difficulty comparing state fiscal year data to other arrays may blunt the utility of this model to show the effects of current developments.
- The second problem is that the model does not display TAPS tariffs (shipping charges). In view of two orders by the Regulatory Commission of Alaska (RCA) requiring significant reductions to TAPS tariffs for the small percentage of TAPS oil (approximately five percent) shipped to in-state destinations and a challenge to the current tariff at FERC by Anadarko Petroleum, a shipper, and by the state of Alaska, [53] one would like to know

[50] This problem is compounded by the fact that state fiscal year petroleum data, as recorded by ADOR, cover seven months of the prior year and five of the current year.

[51] In fact, the model's TAPS tariff and production cost data are actually calendar-year inputs that would be associated with different price and production estimates from the fiscal-year information in the table. This problem will be discussed below.

[52] The importance of this distinction was demonstrated in 1988 and again in 1998, when oil prices dropped to record low levels near the end of the calendar year. Because the data here are arrayed in fiscal year terms, the low-price months of both episodes appear with the subsequent fiscal year.

[53] Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues* (Order P-97-4[151] / P-97-7[110]), Nov. 26, 2002, and *Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings, Rejecting the TAPS Carriers' Post-2000 Revenue Requirement and Rate Filings, Establishing Permanent Post-2000 Intrastate TAPS Rates, Requiring Refunds, Ordering Release of Escrowed Funds, Letters of Credit, and Bonds; Approving Filings and Affirming Electronic Rulings,* June 11, 2004 (Order No. P-04-3[34]); State of Alaska, *Protest and Petition for Investigation into the Proposed 2005 TAS Tariffs and Complaint and Petitition for Investigation into the 2003 and 2004 TAPS Tariffs by the State of Alaska and Intervention in Any Subsequent Proceedings*, *Corporation* (Federal Regulatory Energy Commission, Docket Nos. IS05-82-000, IS05-80-000, IS05-72-000, IS05-62-000 and IS05-65-000), Dec. 15, 2004; and Anadarko Petroleum Corporation, *Protest, Complaint, Motion to*

how the TAPS tariff figures into the wellhead price shown in ADOR's first block of figures. But the model does not contain this information; it shows only the total transportation costs and the pieces of the TAPS tariff that feed into the net revenue take. Moreover, the high transportation costs shown in Figure III.-1 for FY 2001 and the low costs for FY 2004 raise warning flags, but there is no obvious explanation for these apparently anomalous entries.

- The third issue is the steep escalation of North Slope production or field costs, which ADOR estimates to have more than doubled between FY 1996 and FY 2002, before leveling off.
- Next, for purposes of policy analysis, it is often useful to express results in real or inflation-adjusted dollars. For the purpose of tracking state revenue, it may be simpler and more convenient to record revenue in nominal or unadjusted dollars. But when one wants to compare results over a multi-year period, conversion to inflation-adjusted dollars will be particularly useful for conducting inter-year comparisons and for analyzing the long-term effects of developments.
- Finally, ADOR's treatment of income taxes functions to mask the true profitability of North Slope production and pipeline operations. By assuming that the industry actually pays the nominal (35%) federal income tax rate on its pre-tax revenue, the federal share of the take is overstated and the industry share understated by significant amounts.

These problems works against apprehension of critical issues affecting North Slope operations and may even mask or distort important trends. For this reason, if this model is to be used as a vehicle for understanding and charting the course for North Slope development, these issues must be addressed. They will be considered below in the order in which they were raised.[54]

B. Calendar Year Conversion

Conversion to calendar year data is accomplished in Figure III.-2 on the next page. In anticipation of dealing with transportation costs, in the calendar year format space has been reserved for North Slope feeder pipeline tariffs, TAPS tariffs and marine transportation costs. Combined, these three items comprise the transportation cost component of the revised model.[55]

Intervene, Motion to Consolidate, and Request for Hearing and Other Relief of Anadarko Petroleum Corporation (Federal Regulatory Energy Commission, Docket Nos. IS05-82-000, IS05-80-000, IS05-72-000, IS05-62-000 and IS05-65-000), Dec. 16, 2004.

[54] Since the purpose of inflation adjustment is to provide perspective, it would be academic to conduct that conversion before fundamental problems, such as calendar year formatting, have been resolved. Therefore, inflation adjustments will not be introduced until the model is ready to consider the final issue (income tax treatment).

[55] Two reconciliation items used by ADOR are excluded from this analysis (see discussion at footnote 73).

FIGURE III.-2. Alaska North Slope Production and Associated Pipeline Revenue (CY 1988 – CY 2004)

Calendar Year Price, Production, State Revenue	CY 1988	CY 1989	CY 1990	CY 1991	CY 1992	CY 1993	CY 1994	CY 1995	CY 1996	CY 1997	CY 1998	CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004
(1) ANS Sales Price ($/Bbl)	**$13.52**	**$17.14**	**$21.47**	**$17.35**	**$17.44**	**$15.45**	**$15.20**	**$16.93**	**$20.44**	**$18.98**	**$12.55**	**$17.73**	**$28.28**	**$23.21**	**$24.72**	**$29.64**	**$38.84**
(2) ANS Production (Million Bbl/Yr)	**727.5**	**698.5**	**665.9**	**653.1**	**636.7**	**599.8**	**578.3**	**558.9**	**527.4**	**492.8**	**448.5**	**405.2**	**371.1**	**362.8**	**369.7**	**362.7**	**343.0**
(3) Gross Production Value (Million $)	**9,835.6**	**11,972.1**	**14,296.5**	**11,331.9**	**11,104.4**	**9,266.2**	**8,789.4**	**9,461.8**	**10,779.3**	**9,354.1**	**5,628.6**	**7,184.9**	**10,494.2**	**8,420.8**	**9,140.1**	**10,749.4**	**13,323.8**
(4) Calculating Entries																	
a. Total State and Muni Property Tax	*354.2*	*354.2*	*338.1*	*341.0*	*333.8*	*318.8*	*315.1*	*309.0*	*302.1*	*293.6*	*294.3*	*270.8*	*263.6*	*265.2*	*270.4*	*268.9*	266.0
b. State income tax (Production & P/L)	***162.0***	***141.6***	***151.2***	***175.3***	***141.6***	***67.7***	***73.2***	***151.1***	***221.6***	***234.8***	***172.6***	***153.9***	***250.4***	***258.3***	***164.8***	***225.0***	***367.4***
c. TAPS State & Fed. Inc. Tax (from tariff)	*566.7*	*503.9*	*500.7*	*487.4*	*457.0*	*418.2*	*384.7*	*353.5*	*312.9*	*262.1*	*217.3*	*200.0*	*197.1*	*202.2*	*208.5*	*208.5*	208.5
(5) N. Slope "Feeder" P/L Tariffs	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*
a. State Subtotal (Feeder)																	
b. Federal Subtotal (Feeder)																	
c. Industry Subtotal (Feeder)																	
(6) TAPS Tariff																	
a. Operating and capital costs	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*
b. State and local property tax (TAPS)	70.8	70.8	67.6	68.2	66.8	63.8	63.0	61.8	60.4	58.7	58.9	54.2	52.7	53.0	54.1	53.8	53.2
c. State income tax (TAPS)	113.3	100.8	100.1	97.5	91.4	83.6	76.9	70.7	62.6	52.4	43.5	40.0	39.4	40.4	41.7	41.7	41.7
d. Federal income tax (TAPS)	453.4	403.1	400.6	389.9	365.6	334.6	307.8	282.8	250.3	209.7	173.8	160.0	157.7	161.8	166.8	166.8	166.8
e. After-tax margin	308.2	257.4	303.0	326.1	336.3	320.8	322.0	318.2	309.1	290.1	275.2	254.7	243.2	248.5	256.7	256.7	256.7
f. Recovery of deferred return	558.7	515.1	463.7	419.8	363.5	296.9	245.4	203.7	153.7	81.5	49.5	48.6	50.1	51.1	51.2	51.2	51.2
g. DR&R	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*
(7) Pipeline Net Revenue Split																	
a. State Subtotal (Pipelines)	184.2	171.6	167.8	165.7	158.2	147.4	140.0	132.5	123.0	111.1	102.3	94.2	92.1	93.5	95.8	95.5	94.9
b. Federal Subtotal (Pipelines)	453.4	403.1	400.6	389.9	365.6	334.6	307.8	282.8	250.3	209.7	173.8	160.0	157.7	161.8	166.8	166.8	166.8
c. Industry Subtotal (Pipelines)	866.9	772.5	766.7	745.9	699.8	617.7	567.4	521.8	462.8	371.6	324.7	303.3	293.3	299.6	307.9	307.9	307.9
(8) Marine Transportation (not calculated)																	
(9) Total Transportation Costs	4,306.1	3,800.3	3,624.9	4,140.6	3,610.2	3,075.9	2,688.9	2,973.2	2,747.6	2,193.1	1,847.8	1,714.2	1,651.3	2,035.4	1,841.3	1,740.8	1,543.5
Transportation Costs ($/bbl.)	$5.92	$5.44	$5.44	$6.34	$5.67	$5.13	$4.65	$5.32	$5.21	$4.45	$4.12	$4.23	$4.45	$5.61	$4.98	$4.80	$4.50
(10) Wellhead Revenue	5,529.5	8,171.8	10,671.6	7,191.3	7,494.2	6,190.3	6,100.6	6,488.5	8,031.8	7,161.0	3,780.8	5,470.8	8,842.9	6,385.5	7,298.8	9,008.6	11,780.3
Wellhead Price ($/bbl.)	$7.60	$11.70	$16.03	$11.01	$11.77	$10.32	$10.55	$11.61	$15.23	$14.53	$8.43	$13.50	$23.83	$17.60	$19.74	$24.84	$34.34
(11) State ANS Production Revenue	1,840.5	1,999.8	2,515.1	2,410.6	2,185.2	1,807.2	1,676.8	1,773.7	1,925.8	1,648.4	1,170.0	1,482.0	1,824.7	1,594.3	1,708.7	1,979.8	2,377.4
a. Royalty	**865.4**	**908.4**	**1155.1**	**1069.0**	**965.5**	**802.4**	**745.8**	**816.6**	**909.2**	**781.5**	**543.5**	**773.8**	**1017.9**	**909.9**	**1042.4**	**1257.4**	**1554.8**
b. Severance Tax	**737.5**	**860.4**	**1150.3**	**1132.6**	**1014.9**	**810.8**	**736.7**	**773.9**	**847.4**	**701.0**	**443.0**	**548.6**	**686.9**	**559.3**	**533.6**	**604.5**	**716.4**
c. Spill Respons & Conservation Tax	0.2	2.7	2.6	2.5	2.4	2.4	2.3	1.3	1.2	1.2	1.0	0.8	0.8	0.8	0.8	0.8	0.7
d. State & local Property Tax (production)	283.4	283.4	270.5	272.8	267.0	255.0	252.1	247.2	241.7	234.9	235.4	216.6	210.9	212.2	216.3	215.1	212.8
e. Cook Inlet Revenue (excl. fr. Line [11])	**46.0**	**55.1**	**63.5**	**66.2**	**64.7**	**63.4**	**60.2**	**65.3**	**73.7**	**70.2**	**52.9**	**57.9**	**91.8**	**87.9**	**84.4**	**97.9**	**107.3**
(12) Est. Production Costs (Total)	2,909.9	2,654.3	2,463.8	2,286.0	2,228.5	1,985.2	1,775.2	1,659.9	1,629.6	1,808.7	1,901.6	1,892.5	1,892.5	2,160.9	2,380.4	2,334.8	2,229.6
Est. Production Costs ($/bbl.)	$4.00	$3.80	$3.70	$3.50	$3.50	$3.31	$3.07	$2.97	$3.09	$3.67	$4.24	$4.67	$5.10	$5.96	$6.44	$6.44	$6.50
(13) Production Net Revenue Split																	
a. State Income Tax (Production)	**48.7**	**40.8**	**51.0**	**77.8**	**50.2**	**-15.9**	**-3.8**	**80.4**	**159.0**	**182.3**	**129.1**	**113.9**	**211.0**	**217.8**	**123.1**	**183.3**	**325.7**
b. Federal Income Tax (Production)	230.8	1,192.1	1,950.9	822.0	1,037.2	822.5	906.3	1,019.5	1,489.9	1,212.0	182.4	674.9	1,701.7	825.8	1,061.4	1,559.9	2,378.0
c. Industry Profit (Production)	428.7	2,214.0	3,623.2	1,526.7	1,926.3	1,527.5	1,683.1	1,893.3	2,767.0	2,250.8	338.7	1,253.3	3,160.3	1,533.6	1,971.2	2,897.0	4,416.4
(14) Production and Pipeline Net Revenue Split:	**4,053.1**	**6,793.9**	**9,475.2**	**6,138.7**	**6,422.4**	**5,241.0**	**5,277.4**	**5,704.0**	**7,177.9**	**5,986.0**	**2,421.2**	**4,081.6**	**7,440.8**	**4,726.4**	**5,434.7**	**7,190.1**	**10,067.1**
a. Total State Share (Production + P/L)	**2,073.4**	**2,212.2**	**2,733.9**	**2,654.1**	**2,393.5**	**1,938.7**	**1,812.9**	**1,986.6**	**2,207.8**	**1,941.9**	**1,401.5**	**1,690.1**	**2,127.9**	**1,905.6**	**1,927.5**	**2,258.6**	**2,798.0**
State Percentage	51.2%	32.6%	28.9%	43.2%	37.3%	37.0%	34.4%	34.8%	30.8%	32.4%	57.9%	41.4%	28.6%	40.3%	35.5%	31.4%	27.8%
b. Federal Revenue	**684.2**	**1,595.3**	**2,351.5**	**1,212.0**	**1,402.8**	**1,157.1**	**1,214.0**	**1,302.3**	**1,740.3**	**1,421.7**	**356.2**	**834.9**	**1,859.4**	**987.6**	**1,228.2**	**1,726.7**	**2,544.8**
Federal Percentage	16.9%	23.5%	24.8%	19.7%	21.8%	22.1%	23.0%	22.8%	24.2%	23.8%	14.7%	20.5%	25.0%	20.9%	22.6%	24.0%	25.3%
c. Total Industry Profits (Production + P/L)	**1,295.6**	**2,986.4**	**4,389.9**	**2,272.6**	**2,626.1**	**2,145.3**	**2,250.5**	**2,415.1**	**3,229.8**	**2,622.4**	**663.4**	**1,556.6**	**3,453.6**	**1,833.2**	**2,279.1**	**3,204.9**	**4,724.3**
Industry Percentage	32.0%	44.0%	46.3%	37.0%	40.9%	40.9%	42.6%	42.3%	45.0%	43.8%	27.4%	38.1%	46.4%	38.8%	41.9%	44.6%	46.9%

Notes:

From Alaska Department of Revenue data (see source and calculating notes in Appendix D).

In comparing the two versions of the model, the reader will note one additional format modification: The order of the totals has been changed to reflect more closely the way the revenue stream is actually calculated. In Line (14), for example, total take comes first; state take (a model constant, as discussed above) is the first item subtracted. Then federal take is calculated. The remaining amount, shown at Line (14c), is total industry profit from the operation of the North Slope and associated pipelines.[56]

Because changes to transportation, production cost and federal income tax components of the model are necessary, these totals are not yet final. Before those changes are made, however, one can observe the effects of the organizing the results on a fiscal or calendar year basis. In each of the last three calendar years, the total net revenue take has been larger than in the corresponding fiscal year. And in each year, the majority of that increase has gone to the industry, widening the gap between the state's share of the net revenue take and that of the industry. The root of the difference is that the calendar year lags the fiscal year and therefore contains seven months of more recent data; during recent years that has meant seven months of higher oil prices. The effects on results for 2004 – the last year shown in Figures III.-1 and III.-2, respectively, are summarized in Figure III.-3.

Figure III.-3. Comparison of Calendar and Fiscal Year Results
(Based on Alaska Dept. of Revenue Estimated Shares)

	Fiscal Year 2004 [(a)] ($ Millions)	*Calendar Yr. 2004* [(b)] ($ Millions)	*Difference* [(c)] ($ Millions)	*Percentage of Difference*
Total Net Revenue	$7,997.8	$10,067.1	$2,069.3	(100.0%)
State Share	$2,514.7	$2,798.0	$283.3	(13.7%)
Federal Share	$1,919.8	$2,544.8	$625.0	(30.2%)
Industry Share	$3,563.4	$4,724.3	$1,160.9	(56.1%)

Notes:

(a) Alaska Dept. of Revenue data (see Figure III.-1, above).
(b) Revised Alaska Dept. of Revenue data (see Figure III.-2, above).
(c) (Calendar year) – (Fiscal Year)

[56] The format revisions in Figure III.-2 were tested by leaving the original values in place; the reformatted results were identical to the original totals. To further test the model revision, entries were arbitrarily changed on both the original and the reformatted version of the model; the changed entries resulted in identical incremental changes to the totals on both worksheets.

The increase in net revenue between calendar year 2004 and fiscal year 2004 – a little over $2.0 billion, results from the fact that the average price of ANS for calendar year 2004 was $7.14 per barrel greater than the FY 2004 price ($38.84 per barrel v. $31.74). As crude oil prices soared, the differential between ANS and the benchmark West Texas Intermediate (WTI) crude oil widened. Historically, ANS sells for approximately $2.00 per barrel less than WTI; but in October 2004, as prices approached $50.00 per barrel, the differential widened to more than $6.00 per barrel during the last two months of 2004. Through early 2005, the differential has averaged slightly over $3.00 per barrel.[57] Alaska officials were nonchalant,[58] but in January 2005, the California state officials charged that major producers were intentionally underpricing West Coast crude oil – including ANS – to reduce royalty payments on crude oil produced in California. According to a report to the California state controller:

> Over many decades, the differential between the various gravities of crude oil was used as a mechanism for fictitious prices to escape the full payment of royalties owed to the state and federal government. … The spread between light and heavy crude oils has increased, although generally even light crude oils on the West Coast, including Alaskan North Slope (ANS), have declined relative to the prices of east of Rockies crude oils. Changes in crude oil supplies, product demand, product prices and refinery operations do not appear to justify this relative decline in West Coast crude prices.[59]

Does the widening of the ANS/WTI differential warrant investigation? The fact that most ANS is transferred from the production arm of the producer to the refining arm of the same company – rather than sold on the open market – heightens the public interest in this question. But the significance of the price term becomes clear only after the switch to a calendar year framework spotlights the importance of carefully monitoring rising crude oil prices.

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[57] ADOR reports ANS and WTI daily prices on-line at http://www.tax.state.ak.us/programs/oil/prices/monthlydata/2005/042005.htm; monthly prices are tracked at "Oil Price Archives" (see footnote 2, above).

[58] ADOR's Fall 2004 *Revenue Sources Boo*k noted the widening of the differential from an historical average of $1.70 per barrel to $6.00 per barrel in October 2004 and commented, "[t]he disruption of production of benchmark WTI (a light sweet crude oil) due to Hurricane Ivan contributed to the widening of the sweet/sour spread" (*Revenue Sources Book*, Fall 2004, p. 29).

[59] Memorandum from IIC., Inc. to Steve Westly (Controller, State of California), "SUBJ: California Crude Oil Pricing," Dec. 9, 2004 (released with: "Westly Calls on Congress to Investigate Oil Pricing: Preliminary Analysis Shows Widening Gap Between California and East of the Rockies Oil Pricing" [press release, Jan. 18, 2005]; accessed at http://www.sco.ca.gov/eo/pressbox/2005/01/oil_investigation0118.pdf, Feb. 21, 2005)

C. Transportation Costs

With the model now switched to calendar year format, it is time to deal with the transportation cost issues at model Lines (5) through (9). This issue was flagged initially for two reasons. First, the model transportation cost entries for fiscal years 2001 and 2004 were not consistent with the transportation cost entries for other years and did not appear to match other reported ADOR data.[60] Secondly, the transportation line was not broken down into components. The latter problem is particularly important because the costs associated with transportation components – specifically marine transportation, the various feeder lines that bring oil from remote fields to Pump Station #1 at Prudhoe Bay and the TAPS system – are all relevant to assessing the economic viability of North Slope petroleum operations. Because these costs are subtracted from the market price of oil to determine the basis for state royalty and severance tax payments, increases in pipeline tariffs result in decreased state revenue. As a rough rule of thumb, every one dollar increase in transportation charges reduces state revenue by approximately $0.19.[61]

Apart from direct effects on state revenue, TAPS tariffs are critical to the course of North Slope development for a variety of reasons and are the subject of long-running legal skirmishes involving producers, shippers, the TAPS owners and the state. As a general proposition, high transportation charges hinder development. More specifically, three companies control more than 90% of the North Slope's production and own a similar share of TAPS. In this situation, excessive TAPS tariffs can inhibit competition to these firms. At year-end 2002, an informal *Petroleum News* survey of key industry participants and observers found that lowering the TAPS tariff by $1.50 per barrel tied with reduced permitting time as the most important thing government could do to ensure the health and growth of Alaska's oil industry.[62]

[60] The reported $5.61 transportation cost figure for 2001 shown in the model exceeded the corresponding for the preceding and subsequent years by more than 10 percent, as well as the amount reported in *Revenue Sources* at that time (See Figure III.-1 and *Revenue Sources*, Spring 2002, where the sum of the FY 2001 transportation items is $5.02 per barrel [Table 16, p. 70] but the difference between wellhead and market is $7.79 [p. 163; since Spring 2003, the difference between wellhead and market price for 2001 has been carried in *Revenue Sources* at $5.61]). The 2004 entry dropped significantly from prior years and did not match the Fall 2004 *Revenue Sources Book* transportation components (most significantly, a net entry for feeder pipelines and differentials is a negative $0.27 in the model but is plus $0.30 in *Revenue Sources* [Table 4-5, p. 31]).

[61] Royalties constitute 12.5% of petroleum value; severance taxes (reduced by the ELF) average approximately 7.5% on the remainder. ($1.00 x 0.125 = $0.125 [royalty]; [$1.00 - $0.125] *0.075 = $0.065 [severance].

[62] " 'Good news' wanted in 2003," *Petroleum News Alaska*, Jan. 19, 2003, p. 1.

In January 2004, the state entered into closed-door talks with the TAPS owners about re-negotiating the 1985 TAPS tariff agreement, which expires in 2011.[63]

In 2002 and again in 2004, the Regulatory Commission of Alaska ordered the TAPS owners to reduce TAPS tariffs to $1.96 per barrel. Among other things, the RCA believed that the TAPS owners were charging shippers for dismantling activities under the Strategic Reconfiguration program, even though the companies had agreed to cease collecting dismantling funds from intrastate shippers. While appealing these rulings in court, in December 2004 the TAPS owners filed new tariffs at FERC with a weighted average of $3.71 per barrel, compared to an average tariff of $3.05 in 2004. As discussed above, the tariff increase drew formal protests from North Slope producer and shipper Anadarko Petroleum Co., and from the state.

At estimated 2005 throughput of 0.933 million bpd, the $0.66 per barrel tariff increase would reduce state take by approximately $42.6 million.[64] Anadarko, as a shipper, would pay its competitors an additional $0.535 per barrel on every barrel it produced on the North Slope.[65] Since the RCA – the only regulatory body that has ever completed a comprehensive TAPS tariff hearing[66] – studied the tariff intensely for more than five years, received more than one million pages in documents, held two extended hearings and has issued two lengthy decisions ordering reduced tariffs, it is not unreasonable to assume that every penny collected in excess of $1.96 per barrel is excess profit. In this case, the state is losing $113.00 million on TAPS overcharges and Anadarko would be paying a shipping overcharge of $1.41 on every barrel produced on the North Slope.[67]

It is clear from the foregoing that that the TAPS owners have financial incentive to overcharge, and that overcharges would constitute a significant public policy concern. Nevertheless, due to confidentiality, essential details of the TAPS tariff remain shrouded in mystery.[68] Under the 1985 settlement agreement that governs TAPS tariffs at FERC, the pipeline tariff is actually a ceiling or maximum

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[63] Alaska Department of Law, "State and TAPS Owners Enter MOU" (press release), Jan. 27, 2004.

[64] $0.66 / bbl. x $0.19 = $0.125 / bbl. state loss; $0.125 * 0.933 million bpd * 365 = $42.6 million.

[65] $0.66 / bbl. - $0.125 reduced royalty and severance = $0.535 / bbl . cost to Anadarko.

[66] The 1985 tariff agreement was forged by a settlement between the TAPS owners and the state; the guiding terms were eventually approved by the FERC and, later, by the RCA's predecessor. The TAPS owners have challenged the RCA's orders in court.

[67] $1.74 / bbl. x $0.19 = $0.331 / bbl. state loss; $0.331 * 0.933 million bpd * 365 = $112.7 million.
$1.74 / bbl. - $0.331 reduced royalty and severance = $1.409 / barrel cost to Anadarko.

[68] See Appendix E for letter from William Corbus (Commissioner, Alaska Department of Revenue) to Richard A. Fineberg, April 7, 2005, listing the legal grounds for not providing requested TAPS tariff information.

allowable tariff that consists of eight basic elements that constitute the TAPS total revenue requirement (TRR). To set the tariff, the annual TRR is divided by estimated total throughput for that year.[69] The ADOR model, as noted above, contains some elements of the tariff, but the published elements comprise less than half the estimated TRR. The exact TRR, hidden behind a veil of confidentiality, cannot be calculated accurately from public data for a number of reasons. One problem is that each TAPS owner's tariff is adjusted annually to deal with shortfalls or excess collections that result from the differences between the estimated and actual throughput. Moreover, on inspection it appears that some of the ADOR estimates are derived from the information on the1999 tariff filings that are no longer valid for current years.

To help the reader understand how TAPS tariffs are built, Figure III.-4 on the following page lists the principal tariff elements and provides rough estimates for each item.[70] Many of the dollar amounts in this figure are rough approximations; the goal is to give the reader a general understanding of the discrete tariff elements and how the individual tariff elements affect total net revenue from the operation of the North Slope fields and associated pipelines. The rough estimates in Figure III.-4 provide a general framework for considering TAPS tariff issues.

[69] The eight tariff elements are: operating expense, depreciation, recovery of deferred return, after-tax margin, income tax allowance, DR&R allowance, non-transportation revenue and net carryover. See: *Settlement Agreement between The State of Alaska and ARCO Pipe Line Co., BP Pipelines Inc., Exxon Pipeline Co., Mobil Alaska Pipeline Co., Union Alaska Pipeline Co. with Respect to the Trans Alaska Pipeline System,* June 28, 1985 (Federal Energy Regulatory Commission Docket OR 78-1), p. 9.

[70] The bases for these estimates are summarized in Appendix D.

Figure III.-4. Estimated TAPS Tariff Elements and Total Revenue Requirement (TRR), 1999-2004

($ Millions, except as indicated)

Line		CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004
(1)	**Estimated TAPS Tariff ($ / bbl.)**	**$2.72**	**$2.84**	**$3.05**	**$3.30**	**$3.24**	**$3.05**
(2)	Estimated TAPS Throughput (Million barrels / yr.)	405.24	371.08	362.81	369.75	362.66	343.00
(3)	Operating *(TSM Line 118)*	511.32	487.76	541.62	641.46	596.32	478.61
	a. Includes TAPS Property Tax (estimated)	*62.00*	*62.00*	*60.34*	*60.34*	*60.34*	*60.34*
(4)	Depreciation *(TSM Line 120)*	48.62	55.17	59.29	64.98	64.98	64.98
(5)	Tax Allowance *(TSM Line 123)*	217.44	210.13	212.80	220.09	221.9107	219.5101
	a. Estimated Federal Income Tax	*173.96*	*168.11*	*170.24*	*176.07*	*177.53*	*175.61*
	b. Estimated State Income Tax	*43.49*	*42.03*	*42.56*	*44.02*	*44.38*	*43.90*
(6)	After-Tax Margin *(TSM Line 122)*	259.26	240.21	237.23	243.84	242.41	233.88
	a. Per-barrel Allowance (TSM Line 97)	*237.47*	*217.45*	*212.61*	*216.67*	*212.52*	*201.00*
	b. Return on New Investment (TSM Line 105)	*21.79*	*22.76*	*24.62*	*27.17*	*29.89*	*32.88*
(7)	Recovery of Deferred Return *(TSM Line 121)*	48.60	50.12	51.13	51.20	51.2	51.2
(8)	DR&R *(TSM Line 117)*	3.63	3.65	3.45	3.23	2.853	2.61
(9)	Non-Transportation Revenue + Prior-Year Adjustments	_____ ?	_____ ?	_____ ?	_____ ?	_____ ?	_____ ?
(10)	**Estimated Total Transportation Revenue Requirement ***	**1,102.26**	**1,053.88**	**1,106.57**	**1,220.16**	**1,175.03**	**1,046.15**

* These approximations demonstrate the way the TAPS Total Revenue Requirement (TRR) is determined under the 1985 TAPS tariff settlement agreement. Due to the absence of reliable public information, these estimates may not reflect actual tariff collections.

(See sources and calculating notes in Appendix D.)

The background information on TAPS tariffs presented here lays the groundwork for considering this question: Could the TAPS Strategic Reconfiguration program account for the increase in the tariffs filed by the TAPS owners for 2005? Figure III.-5 depicts hypothetical total outlays for the Strategic Reconfiguration of both the pipeline and the VMT. As in Figure III.-4, these are rough calculations, based on the best information available to the public. They are presented to help the reader understand the kind of information needed to evaluate TAPS tariff issues. Alyeska Pipeline Service Co. has estimated the pipeline portion of the Strategic Reconfiguration project at $250 million, with transition to automated pump stations scheduled for 2005; recently, however, Alyeska announced an unspecified project delay. The VMT portion was scheduled to be conducted between 2005 and 2008 but has been delayed. To avoid underestimating the annual tariff requirement for Strategic Reconfiguration, Figure III.-5 increases the pipeline upgrades to $300 million, with the bulk of the expenditures in 2005 and 2006; the VMT upgrades are estimated at $250 million between 2005 and 2008. Line (3) sums the annual outlays. An hypothetical capitalization schedule based on a standard Internal Revenue Service accelerated depreciation schedule is shown below the annual outlays. The sum of each year's depreciation recovery on this accelerated basis is summed in the "Totals" column on the right-hand side of the figure. The accelerated depreciation schedule shows $47.5 million recovered in 2005, with a peak of $102.9 million in 2007.[71]

In sum, the hypothetical depreciation recovery of $42.5 million in 2005 would represent a $35.0 million increase over the estimated tariff charges for Strategic Reconfiguration in 2004. But an increase in the tariff from $3.05 per barrel to $3.71 results in additional tariff collections of approximately $225.0 million.[72] Are the TAPS owners overcharging? Again, refinement of the ADOR model has helped shed light on an important public policy issue that was not revealed in the original model.

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[71] Although the data are not available to the public, ADOR staff advises that the tariff formula for capital expenditures would probably reduce the depreciation amount that the TAPS owners could charge in 2005 tariff, compared to the tax accelerated depreciation basis shown in Figure III.-5.

[72] $0.66 per barrel * 0.933 million bpd * 365 = $225.0 million.

Figure III.-5. TAPS Strategic Reconfiguration Estimated Cost and Capitalization Worksheet ($ Millions)

Strategic Reconfiguration Outla	2002	2003	2004	2005	2006	2007	2008	2009	Totals
Pipeline Pump Station Upgrade (1)		10	25	150	100	15			300
VMT Reconfiguration (2)			10	75	100	50	15		250
Total Strategic Reconfiguration Outlays		10	35	225	200	65	15		550
Depreciation Schedule (MACRS) (3)									Annual Tariff Revenue Requirement
2002									
2003		1.429							1.429
2004		2.449	5.002						7.451
2005		1.749	8.572	32.153					**42.473**
2006		1.249	6.122	55.103	28.580				91.053
2007		0.893	4.372	39.353	48.980	9.289			102.886
2008		0.892	3.126	28.103	34.980	15.919	2.144		85.162
2009		0.893	3.122	20.093	24.980	11.369	3.674		64.130
2010		0.446	3.126	20.070	17.860	8.119	2.624		52.244
2011			1.561	20.093	17.840	5.805	1.874		47.172
2012				10.035	17.860	5.798	1.340		35.033
2013					8.920	5.805	1.338		16.063
2014						2.899	1.340		4.239
2015							0.669		0.669
2016									
		10.000	35.000	225.000	200.000	65.000	14.331		549.331

Notes:

(1) Assumed $300 million expense, with bulk of purchases in 2005 and 2006.

(2) Assumed $250 million capital expense, beginning in 2005 with completion in 2008

(3) Internal Revenue Service schedule for 7-year accelerated depreciation of capital goods.

Figure III.-6 combines the total TAPS tariff requirement shown Figure III.-4 with ADOR estimates of marine transportation costs and feeder pipeline costs. The resulting figure represents total transportation costs that may be used to refine the transportation costs shown in Figure III.-1, thereby resolving the unexplained contrasts in total transportation costs that were observed in 2001 ($5.61 per barrel) and 2004 ($4.50 per barrel). [73]

[73] The expansion of the transportation cost entry reveals two reconciliation items that ADOR includes with feeder pipeline tariffs as "other adjustments" in *Revenue Sources.* Since neither item appears to affect market prices or value received by the state, these two items have been removed. The differential items that are no longer calculated are:

(1) The TAPS Quality Bank differential, which represents the change in value of any particular stream of North Slope crude oil when it is blended with other North Slope crude oil streams of higher or lower value. Since the market value of ANS is the value of the blended ANS stream, for purposes of this analysis it is not necessary to deal with the Quality Bank adjustments among ANS producers, including the state. (For a short but detailed discussion of quality bank, see Alaska Department of Natural Resources, *Final Finding and Determination To Sell Royalty Oil in a Competitive Sale*, August 7, 2000, pp. 9-12 [http://www.dog.dnr.state.ak.us/oil/programs/royalty/rik_sale/rik_sale_final_finding_080900.pdf]).

(2) The "wellhead to market differential," which represents an artificial reconciliation number that ADOR uses to force the wellhead amounts actually paid by each producer to match the average wellhead price reported by all producers. According to ADOR staff, this artificial or "forcing" entry is needed because the reported annual average wellhead price is an aggregate number that is different from the wellhead values reported monthly by individual taxpayers, each of whose calculations are based on inputs that are liable to be different from those of other taxpayers. (This description is based on a worksheet provided by ADOR staff and follow-up conversations in March 2005.)

Figure III.-6. Estimated Alaska North Slope Transportation Costs and Adjustments to Market Price ($ / bbl.)

Line		1999	2000	2001	2002	2003	2004	2005
(1)	TAPS Tariff	2.72	2.84	3.05	3.30	3.24	3.05	3.72
(2)	Feeder Line Tariiffs	0.11	0.12	0.13	0.31	0.36	0.46	0.51
(3)	Marine	1.64	1.74	1.88	1.74	1.58	1.60	1.63
(4)	**Total Transportation**	**4.47**	**4.70**	**5.06**	**5.35**	**5.18**	**5.11**	**5.86**
Non-Add Items (for reference)								
(5)	Quality Bank Differential	0.01	(0.11)	(0.19)	(0.17)	(0.19)	<n.a.>	<n.a.>
(6)	Wellhead to Mkt. Differential	(0.36)	0.01	0.12	(0.17)	(0.23)	<n.a.>	<n.a.>

(See sources and calculating notes in Appendix D.)

(Research Associates, Ester, Alaska 99725 (March 2005)

D. Production Costs

It is now time to consider the question of field or production costs. This issue warrants careful attention for three reasons:

- First, increasing costs associated with pumping from aging fields can destroy profit margins. As fields age, they produce more water and sediments with the oil. Producing equipment has to run longer to get the number of barrels the same equipment formerly produced, and then the extraneous material has to be separated and disposed of. Consequently, costs go up.
- Second, elevated costs on new projects – either real or projected – can cause profit-sensitive investors to by-pass a project in favor of another endeavor elsewhere in the world that is not similarly handicapped. Cost comparison must be carefully analyzed, as demonstrated by the confusion about the Wood Mackenzie reports discussed in Section II.
- Finally, According to ADOR forecast data, by 2015 heavy oil production (API gravity 10-20^{o}) will increase from about eight to more than 16 percent of total ANS production.[74] That is just a small portion of the available North Slope heavy oil deposits, but the cost reductions that have brought heavy oil reservoirs near Prudhoe Bay into production will not result in new heavy oil investment unless the cost structure of new heavy oil projects continue to be favorable.[75]

For all of these reasons, production costs have much to do with how much oil will be flowing through TAPS in years to come. To investigate this issue, it will be useful at the outset to separate production costs into its basic components. Production costs are typically divided into (a) operating or lifting costs and (b) capital expenditures, which are sometimes identified by their principal recovery mechanisms, depletion, depreciation and amortization (DD&A). Operating or lifting costs are typically recovered ("expensed") in the year the funds were expended; in contrast, capital costs are amortized, or paid off in installments through time.[76]

[74] Calculated from in-house forecast data provided by ADOR.

[75] See: Richard F. Meyer and Emil D. Attanasi, "Natural Bitumen and Extra-Heavy Oil," *2004 Survey of Energy Resources* (World Energy Council), pp. 93-117. According to Meyer, "to my knowledge no cost data are presently available" (personal communication, Jan. 30, 2005). For a recent press report on North Slope heavy oil development, see: Mary Pemberton, "Slope firms weigh in on heavy oil," *Fairbanks Daily News-Miner*, April 17, 2005, p. D1.

[76] For a chart showing the standard role of operating and capital expenditures in assessing the economics of petroleum operations, see: Arthur D. Little/John Gault, *Review of International Competitiveness of Alaska's Fiscal System* (Final Report), September 1995, p. 7. (Operating and capital expense issues and their importance to North Slope development are discussed in more detail in the author's *How Much is Enough? Estimated Industry Profits from Alaska North Slope and Associated Pipeline Operations, 1993 – 1998* [Oilwatch Alaska], Dec. 9, 1998, pp. 16-21.)

On inspection of the ADOR data, the steep increase in production costs since 1997 stands in marked contrast to the production cost decline between 1988 and 1996. As shown in Line (12) of Figure III.-2, during the former period field costs declined by 25 percent. But then they began to increase sharply – so fast, in fact, that between 1997 and 2002 production costs reportedly doubled. And then, suddenly, in 2002, those costs leveled off again.[77] The decrease between 1988 and 1996 was consistent with national trends.[78] And the leveling in 2002 matches proud statements by ConocoPhillips officials.[79] But do the reasons given above explain a doubling of field costs between 1997 and 2002? If so, why did those costs suddenly level off after 2002?

The production cost estimates in question and the way that ADOR calculated them are shown in the following figure.

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[77] ADOR took its cost estimates for 1993-1996 directly from the author's 1998 report, *How Much Is Enough? Estimated Industry Profits from Alaska North Slope Production and Associated Pipeline Operations, 1993 – 1998* (Oilwatch Alaska, 1998). The cost estimates in that report, covering 1993 through 1998, were developed from a review of press, company and trade reports. The department derived its 2000 through 2003 estimates from data in the ConocoPhillips 2002 Annual Report, then increased 1997 through 1999 to smooth the transition from lower to higher cost estimates (see Figure III.-7 on the following page).

[78] See, for example, Dirk Beveridge (Associated Press), "Crude comes cut-rate; methods slash oil-finding costs," *Anchorage Daily News*, April 2, 1998, p. F-1.

[79] In its 2002 annual report, ConocoPhillips boasted that "Alaska Maintains Production, Keeps Costs Flat." According to ConocoPhillips Alaska President Kevin Meyers, "Maintaining flat operating costs isn't easy, but we achieved it in 2002, and we'll continue pursuing it as our goal in 2003." *ConocoPhillips 2002 Annual Report,* p. 12 (http://www.conocophillips.com/NR/rdonlyres/49174582-1D33-4336-9F28-432C4045D03F/0/cp02op03.pdf).

Figure III.-7. ADOR Estimates of North Slope Production Costs – $ / bbl.

Year	*Estimated Field Cost*	*ADOR Basis for Estimate*
1996	$3.09 / bbl.	*How Much Is Enough?* (1998 report)
1997	$3.67 / bbl.	*How Much Is Enough?* estimate ($3.17/bbl.) + $0.50
1998	$4.24 / bbl	*How Much Is Enough?* estimate ($3.24/bbl.) + $1.00
1999	$4.67 / bbl.	(4.24 + 5.10) / 2
2000	$5.10 / bbl.	ADOR (derived from ConocoPhillips Annual Report)
2001	$5.96 / bbl.	ADOR (derived from ConocoPhillips Annual Report)
2002	$6.44 / bbl.	ADOR (derived from ConocoPhillips Annual Report)
2003	$6.44 / bbl.	ADOR (2002 estimate, carried forward)
2004	$6.50 / bbl.	ADOR (basis unknown)

Source: Alaska Department of Revenue, "Shares of Alaska's Oil Revenue Pie (Production and Value Added by TAPS)," worksheet in Microsoft Excel workbook, "Integrated Profit Model," February 2005.

In response to an inquiry about profit and cost estimates in October 2003, ADOR explained that the agency had derived its ANS production cost estimates from the *ConocoPhillips 2002 Annual Report*. Because ConocoPhillips produces about 40 percent of the North Slope's crude oil from various fields, ADOR reasoned, its cost structure could be regarded as representative. But to use those estimates, ADOR continued, state estimates of severance and property tax payments had to be subtracted from the ConocoPhillips estimates of field operating costs. ADOR calculated that these adjustments to the ConocoPhillips numbers resulted in total production costs of $5.96 in 2001 and $6.44 in 2002 – the figures shown in the ADOR take analysis.[80] For 2003 and 2004, ADOR apparently carried the 2002 estimate forward.

ADOR's approach makes sense in the abstract, but this fundamental, real-world question remains: Why did production costs begin to rise so suddenly in 1997 after nearly a decade of steady decline? ADOR felt that factors such as the increased costs of dealing with additional water and sediments were a driving factor; why did those costs level out in 2002?

[80] The 2000 numbers were a bit harder to analyze because the ConocoPhillips cost data apparently reflected only that fraction of the year's operations after the acquisition of ARCO Alaska (the purchase was announced in March 2000 and completed in stages in the following months).

Information in the *ConocoPhillips 2003 Annual Report* threw another monkey-wrench into ADOR's production cost estimates; for 2003, the company's updated Alaska cost information showed a significant decline in production costs.[81] In light of all the attention industry executives give to controlling expenditures on the North Slope, one would think that news of major cost declines would have made headlines and rung bells in Alaska. But that bell has not rung. And although ConocoPhillips bragged to shareholders about holding Alaska operating costs constant in its 2002 annual report, the 2003 volume does not mention reduced Alaska operating costs.

Did a major decline in North Slope per-barrel production costs in 2003 really take place? Another possibility is that the reported increases in the two prior years were actually the result of extraordinary expenditures associated with the acquisition of ARCO Alaska by ConocoPhillips (then Phillips) in the spring of 2000. Following this line of inquiry, it is important to ask what portion of the putative production expenditure increases between 1996 and 2002 were real? Do a significant portion of them reflect bookkeeping entries that are appropriate for tax purposes but are not indicative of actual field expenditures? And if so, where in the model were those tax advantages recognized? The following observations suggest that the ConocoPhillips field cost estimates on which ADOR relied may have been inflated by merger-related bookkeeping entries that included items reported in aid of securing tax deductions:

- The operating cost estimates on which ADOR relied included an entry for capital expenditures in support of operations; ADOR employed that figure as a plug factor. Thus, when ADOR backed property and severance tax out of the reported operating expenses, ADOR increased the plug factor to maintain the total lifting cost figure ConocoPhillips reported.[82]
- It is widely recognized that there are many items in the tax code designed to permit corporations to pay less tax, or perhaps no income at all in a given year. These include, for example, the tax benefits of accelerated depreciation and costs that can be juggled to minimize taxable income, which some accountants refer to as "gray area costs."[83] Therefore, it appears likely that both the operating figure and the support capital figure included items that did not represent field costs.

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[81] In the *ConocoPhillips 2003 Annual Report* (p. 103), average production costs (including state taxes) were reported to have increased from $5.48 to $5.73 per barrel of oil equivalent between 2002 and 2003, while Depreciation, Depletion and Amortization costs dropped from $3.94 to $3.15 per barrel of oil equivalent, for a total production cost total of $8.88.

[82] Alaska Department of Revenue worksheet attached to "Memorandum to Chuck Logsdon regarding profitability of North Slope operations on October 20, 2003," Oct. 29, 2003.

[83] John A. Tracy, *How To Read a Financial Report: For Managers, Enterpreneurs, Lenders, Lawyers and Investors* (4th ed.), pp. 58, 138-139, 141-142

- Perhaps it is the existence of loopholes such as those mentioned in the preceding paragraph that led ADOR to advise the Legislature in January 2000 that "[i]t is virtually impossible to calculate the effect of the merger on this type tax." The department also noted that "combining prior year returns of the merging companies shows less income tax."[84] Items that reduce tax payments must be put on the books somewhere to justify those tax breaks, and it would be surprising if some – if not many – of those items were not associated with the ConocoPhillips acquisition of the Alaska properties that now constitute such a large and important part of the company's operations.
- A report by a national tax research group calculated that ConocoPhillips paid an effective income tax rate of 7.1% in 2001 and 5.7% in 2002, before rising to 13.0% in 2003. According to that report, ConocoPhillips reduced its income taxes by $1.363 billion in 2001 and $0.716 billion in 2002 through accelerated depreciation; that figure fell to $0.289 billion in 2003 as its income tax payments rose.[85] (The effect of income tax rates will be discussed later in this chapter.)

This analysis suggests that the ConocoPhillips production cost estimates for 2001 and 2002 may not reflect actual costs, and that there is good reason to attach higher credence to the lower production cost estimates from the 2003 ConocoPhillips annual report. In any event, merger-related expenditures would have been capitalized and therefore should be reflected in future production costs, where the increase in depreciation of capital expenses would tend to balance reduced operating expenditures.[86]

Figure III.-8 shows how North Slope production costs can be estimated using the ConocoPhillips Alaska production cost estimate. These calculations are summarized on a per-barrel basis at Line (15), where the 2003 production cost estimate of $5.41 per barrel is down 13.4 percent from the 2002 estimate.[87]

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[84] Alaska Department of Revenue, "Oil Revenue and the BP/ARCO Merger" (slide presentation to the Senate Finance Committee, Jan. 11, 2000.

[85] Robert S. McIntyre and T.D. Coo Nguyen, *Corporate Income Taxes in the Bush Years,* Citizens for Tax Justice and the Institute on Taxation and Economic Policy, September 2004, pp. 9, 24.

[86] BP asserted at the time of the merger that if it were permitted to acquire ARCO Alaska, the consolidation would result in lower expenses. That consolidation never took place. The management of Prudhoe Bay field was eventually consolidated, but the connection between that event and the ConocoPhillips 2003 cost estimate is somewhat tenuous. Moreover, the same questions would appear to apply to that organizational change.

[87] The adjustments calculated in this report and shown in Figure III.-4 (principally the removal of severance and property tax payments) resulted in a 2003 North Slope production cost estimate of $5.41 for ConocoPhillips, compared to $6.25 in 2002. (The 2001 and 2002 estimates in this report are, respectively, $0.08 and $0.14 less than the ADOR estimates; these differences are discussed in the notes to Figure III.-4. The gap between the two recalculations of ConocoPhillips

Revised estimates for 1999 through 2004 are calculated in Line (16). From the 1998 ADOR cost estimate of $4.24 per barrel, [88] the intervening years are increased in equal increments to reach the $5.41 estimate for 2003; for purposes of this analysis, that rate of change is carried forward to 2004.

Again, refinement of the ADOR model leads to a very different understanding of an important determinant of North Slope development.

estimate for the year 2000 probably results in large part from different assumptions regarding the timing of the staged transfer of assets from the former ARCO Alaska to Phillips in 2000.)

[88] ADOR's 1998 increase of $1.00 per barrel to the *How Much Is Enough*? estimate of $3.24 per barrel has not been reviewed.

Figure III.-8. Estimates of Alaska North Slope Production Costs based on ConocoPhillips Annual Report Data

Line		1999	2000	2001	2002	2003	2004
	North Slope Production						
(1)	Estimated Net ANS Production (mmboe-oil+ngl)		82.49	132.86	129.58	127.02	
(2)	Est. production grossed up for royalty (mmboe)		94.27	151.84	148.09	145.17	
(3)	**Total Alaska Production costs**		494.00	784.00	769.00	792.00	
(4)	Estimated North Slope Production Costs		438.78	720.90	706.33	702.17	
(5)	Property Tax		51.69	80.21	81.79	81.33	
(6)	Severance and Conservation Tax ($mm)		171.57	236.48	206.26	233.73	
(7)	Estimated Computed Lifting Costs		188.55	320.25	327.65	335.06	
(8)	ADOR Estimated Amortized Support Costs		26.97	83.95	90.62	52.05	
(9)	**Total Alaska DD&A (E&P)**		305.00	531.00	552.00	436.00	
(10)	Est. ANS DD&A (E&P)		270.91	488.26	507.01	398.11	
	North Slope Per-barrel Costs						
(11)	Est. Lifting Costs (N. Slope)	$1.91	$2.00	$2.11	$2.21	$2.31	
(12)	*N. Slope DD&A (E&P subtotal)*	*$2.36*	*$3.24*	*$3.22*	*$3.42*	*$2.74*	
(13)	*N. Slope DD&A (Support subtotal)*	*$0.40*	*$0.29*	*$0.55*	*$0.61*	*$0.36*	
(14)	Total N. Slope DD&A (Support + E&P)	$2.76	$3.52	$3.77	$4.04	$3.10	
(15)	Lifting Costs + DD&A (based on CP annual report)	$4.67	$5.52	$5.88	$6.25	$5.41	
(16)	**Adjusted Lifting Costs + DD&A**	**$4.47**	**$4.71**	**$4.94**	**$5.18**	**$5.41**	**$5.64**

Notes:

Derived from ConocoPhillips 2002 and 2003 Annual Report data (see source and calculating notes in Appendix D.).

Explanation of differences from Figure III.-2, Line [12]: (1) Production costs reduced to exclude Cook Inlet production costs (on pro-rata boe basis); this has the effect of reducing the amortized support costs, which were determined by subtracting operating costs and tax elements from the operating total, then added to the capital cost line (in accord with annual report). (2) Property tax and severance calculated using spreadsheet estimating factors, net of Cook Inlet volumes and adjusted to calendar years to reconcile with ConocoPhillips annual report data, which has the net effect of decreasing the residual amortized support costs. (Both changes have the net effect of reducing the capital component of the production cost estimates.)

E. The Next Step: Incorporating Revised Cost Estimates

The relevant transportation cost entries from Figure III.-6 and production cost data from Figure III.-8 are incorporated into the revenue take model at the appropriate lines of Figure III.-9 on the following page. The net effect of these changes and additions to the model is not, on balance, large; the major shifts in the apparent distribution of the take occurred in the shift from fiscal to calendar years at Figure III.-2. Nevertheless, the subsequent refinements make the model much more useful for identifying trends and spotlighting problems. For example, the issues of field costs and TAPS tariffs are now clearly in focus. Note that in the revised compilation of estimated transportation costs for 2004 at model Line (9) increases the 2004 entry from $4.50 per barrel to $5.11, reducing the wellhead value and, accordingly the estimated industry and federal shares of the take. These additions function to offset the decrease in production costs at Line (12), discussed above. Inclusion of both is necessary in order to ensure that the trends in both important areas are correctly identified.

With the exception of feeder pipeline tariffs (Line [5]) and DR&R (Line [6g]), the adjustments to the model have been limited to the last eight years. The past collection of TAPS DR&R revenue through the tariff stream stands as a reminder that those who negotiate on behalf of the public do not always get it right. That income is part of the $1.5 billion collected through the TAPS tariff. These sums include income tax payments (along with a surplus tax payment since the tax amount was calculated at the former 46% nominal rate, even though that rate was replaced by a lower rate of 34% [now 35%] in 1986). At some future point, when a portion of that money is spent on dismantling, the TAPS owners will record a tax deduction on their outlays. In the meantime, that money – and its earnings – is theirs to keep.[89]

For the most part, this analysis has focused on understanding the effects of high oil prices. But in view of the volatility of oil prices, a petroleum fiscal regime should also be evaluated in terms of its performance at low oil prices. In this regard, it is noteworthy that even in times of low prices the industry still makes a profit on its Alaska operations. In 1998, for example, the industry's share of the net revenue take was $674.0 million, more than half of which was attributable to pipeline operations. The fact that the North Slope production and pipeline operations remain profitable in hard times sets this business venture apart from other industrial giants – IBM and General Motors, for example – that lose money during hard times.

[89] In June 2004 the author reported to the Prince William Sound RCAC on this aspect of the TAPS tariff; see: Richard A. Fineberg, *Trans-Alaska Pipeline System Dismantling, Removal and Restoration (DR&R): Background Report and Recommendations* (prepared for the Prince William Sound Regional Citizens' Advisory Committee), June 24, 2004.

Figure III.-9 Revised Estimated Shares of Alaska North Slope Production and Associated Pipeline Revenue (CY 1988 – 2004)

(Nominal Dollars)

	Revised Transportation, Production Costs	CY 1988	CY 1989	CY 1990	CY 1991	CY 1992	CY 1993	CY 1994	CY 1995	CY 1996	CY 1997	CY 1998	CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004
(1)	ANS Sales Price ($/Bbl)	$13.52	$17.14	$21.47	$17.35	$17.44	$15.45	$15.20	$16.93	$20.44	$18.98	$12.55	$17.73	$28.28	$23.21	$24.72	$29.64	$38.84
(2)	ANS Production (Million Bbl/Yr)	727.5	698.5	665.9	653.1	636.7	599.8	578.3	558.9	527.4	492.8	448.5	405.2	371.1	362.8	369.7	362.7	343.0
(3)	Gross Production Value (Million $)	9,835.6	11,972.1	14,296.5	11,331.9	11,104.4	9,266.2	8,789.4	9,461.8	10,779.3	9,354.1	5,628.6	7,184.9	10,494.2	8,420.8	9,140.1	10,749.4	13,323.8
(4)	*Calculating Entries*																	
	a. Total State and Muni Property Tax	354.2	354.2	338.1	341.0	333.8	318.8	315.1	309.0	302.1	293.6	294.3	270.8	263.6	265.2	270.4	268.9	266.0
	b. State income tax (Production & P/L)	162.0	141.6	151.2	175.3	141.6	67.7	73.2	151.1	221.6	234.8	172.6	153.9	250.4	258.3	164.8	225.0	367.4
	c. TAPS State & Fed. Inc. Tax (from tariff)	566.7	503.9	500.7	487.4	457.0	418.2	384.7	353.5	312.9	262.1	217.3	217.4	210.1	212.8	220.1	221.9	219.5
(5)	**N. Slope "Feeder" P/L Tariffs**	65.3	65.3	65.3	65.3	63.7	48.0	46.3	44.7	42.2	44.4	44.8	44.6	44.5	47.2	114.6	130.6	157.8
	a. State Subtotal (Feeder)																	
	b. *Federal Subtotal (Feeder)*																	
	c. Industry Subtotal (Feeder)	9.8	9.8	9.8	9.8	9.6	7.2	6.9	6.7	6.3	6.7	6.7	6.7	6.7	7.1	17.2	19.6	23.7
(6)	**Estimated TAPS Tariff**	2413.4	2311.9	2353.8	2219.5	2151.0	1930.7	2057.5	1722.2	1514.3	1341.4	1157.4	1102.3	1053.9	1106.6	1220.2	1175.0	1046.2
	a. Operating and capital costs	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	511.3	480.7	528.9	624.8	575.2	452.2
	b. State and local property tax (TAPS)	70.8	70.8	67.6	68.2	66.8	63.8	63.0	61.8	69.0	66.6	64.0	62.0	62.0	60.0	60.0	60.0	60.0
	c. State income tax (TAPS)	113.3	100.8	100.1	97.5	91.4	83.6	76.9	70.7	62.6	52.4	43.5	43.5	42.0	42.6	44.0	44.4	43.9
	d. Federal income tax (TAPS)	453.4	403.1	400.6	389.9	365.6	334.6	307.8	282.8	250.3	209.7	173.8	174.0	168.1	170.2	176.1	177.5	175.6
	e. After-tax margin	308.2	257.4	303.0	326.1	336.3	320.8	322.0	318.2	309.1	290.1	275.2	259.3	247.3	250.3	260.8	263.8	260.6
	f. Recovery of deferred return	558.7	515.1	463.7	419.8	363.5	296.9	245.4	203.7	153.7	81.5	49.5	48.6	50.1	51.1	51.2	51.2	51.2
	g. DR&R	85.4	73.2	60.7	33.2	40.3	31.2	24.4	19.3	13.8	8.4	3.9	3.6	3.7	3.5	3.2	2.9	2.6
(7)	Pipeline Net Revenue Split																	
	a. State Subtotal (Pipelines)	184.2	171.6	167.8	165.7	158.2	147.4	140.0	132.5	131.6	119.0	107.5	105.5	104.0	102.6	104.0	104.4	103.9
	b. Federal Subtotal (Pipelines)	453.4	403.1	400.6	389.9	365.6	334.6	307.8	282.8	250.3	209.7	173.8	174.0	168.1	170.2	176.1	177.5	175.6
	c. Industry Subtotal (Pipelines)	923.2	820.8	806.7	767.8	726.0	638.0	583.3	534.4	471.8	377.1	327.2	310.2	299.7	303.6	314.1	316.9	313.5
(8)	**Marine Transportation**	1,827.5	1,423.1	1,205.8	1,094.2	991.2	780.8	799.6	776.2	787.2	700.3	628.1	664.6	645.7	682.1	643.4	573.0	548.8
(9)	**Revised Total Transportation Costs**	4,306.1	3,800.3	3,624.9	3,379.0	3,205.9	2,759.6	2,903.4	2,543.1	2,343.7	2,086.0	1,830.4	1,811.4	1,744.1	1,835.8	1,978.1	1,878.6	1,752.8
	Transportation Costs ($/bbl.)	$5.92	$5.44	$5.44	$5.17	$5.04	$4.60	$5.02	$4.55	$4.44	$4.23	$4.08	$4.47	$4.70	$5.06	$5.35	$5.18	$5.11
(10)	Wellhead Revenue	5,529.5	8,171.8	10,671.6	7,952.9	7,898.5	6,506.7	5,886.1	6,918.6	8,435.6	7,268.1	3,798.2	5,373.5	8,750.1	6,585.0	7,162.0	8,870.8	11,571.1
	Wellhead Price ($/bbl.)	$7.60	$11.70	$16.03	$12.18	$12.40	$10.85	$10.18	$12.38	$16.00	$14.75	$8.47	$13.26	$23.58	$18.15	$19.37	$24.46	$33.73
(11)	State ANS Production Revenue	1,840.5	1,999.8	2,515.1	2,410.6	2,185.2	1,807.2	1,676.8	1,773.7	1,925.8	1,648.4	1,170.0	1,482.0	1,824.7	1,594.3	1,708.7	1,979.8	2,377.4
	a. Royalty	865.4	908.4	1155.1	1069.0	965.5	802.4	745.8	816.6	909.2	781.5	543.5	773.8	1017.9	909.9	1042.4	1257.4	1554.8
	b. Severance Tax	737.5	860.4	1150.3	1132.6	1014.9	810.8	736.7	773.9	847.4	701.0	443.0	548.6	686.9	559.3	533.6	604.5	716.4
	c. Spill Respons & Conservation Tax	0.2	2.7	2.6	2.5	2.4	2.4	2.3	1.3	1.2	1.2	1.0	0.8	0.8	0.8	0.8	0.8	0.7
	d. State & local Property Tax (production)	283.4	283.4	270.5	272.8	267.0	255.0	252.1	247.2	241.7	234.9	235.4	216.6	210.9	212.2	216.3	215.1	212.8
	e. Cook Inlet Revenue (excl. fr. Line [11])	46.0	55.1	63.5	66.2	64.7	63.4	60.2	65.3	73.7	70.2	52.9	57.9	91.8	87.9	84.4	97.9	107.3
(12)	Est. Production Costs (Total)	2,909.9	2,654.3	2,463.8	2,286.0	2,228.5	1,985.2	1,775.2	1,659.9	1,629.6	1,808.7	1,901.6	1,813.0	1,747.1	1,793.0	1,913.8	1,962.0	1,935.9
	a Est. Production Costs ($/bbl.)	$4.00	$3.80	$3.70	$3.50	$3.50	$3.31	$3.07	$2.97	$3.09	$3.67	$4.24	$4.47	$4.71	$4.94	$5.18	$5.41	$5.64
(13)	Production Net Revenue Split																	
	a. State Income Tax (Production)	48.7	40.8	51.0	77.8	50.2	-15.9	-3.8	80.4	159.0	182.3	129.1	110.4	208.4	215.7	120.7	180.6	323.5
	b. Federal Income Tax (Production)	230.8	1,192.1	1,950.9	1,088.6	1,178.8	933.3	831.2	1,170.0	1,628.3	1,246.7	186.7	667.1	1,717.8	1,022.7	1,175.6	1,640.9	2,406.0
	c. Industry Profit (Production)	428.7	2,214.0	3,623.2	2,021.7	2,189.1	1,733.2	1,543.6	2,172.9	3,024.0	2,315.4	346.7	1,238.9	3,190.2	1,899.3	2,183.2	3,047.4	4,468.2
(14)	**Production and Pipeline Net Revenue Split:**	4,109.5	6,842.2	9,515.3	6,922.1	6,852.9	5,577.7	5,078.8	6,146.6	7,590.7	6,098.6	2,441.1	4,088.1	7,513.0	5,308.4	5,782.4	7,447.5	10,168.2
	a. Total State Share (Production + P/L)	2,073.4	2,212.2	2,733.9	2,654.1	2,393.5	1,938.7	1,812.9	1,986.6	2,216.4	1,949.7	1,406.6	1,697.9	2,137.1	1,912.5	1,933.4	2,264.8	2,804.8
	State Percentage	50.5%	32.3%	28.7%	38.3%	34.9%	34.8%	35.7%	32.3%	29.2%	32.0%	57.6%	41.5%	28.4%	36.0%	33.4%	30.4%	27.6%
	b. Federal Revenue	684.2	1,595.3	2,351.5	1,478.5	1,544.3	1,267.8	1,139.0	1,452.8	1,878.6	1,456.4	360.5	841.1	1,885.9	1,193.0	1,351.6	1,818.4	2,581.6
	Federal Percentage	16.6%	23.3%	24.7%	21.4%	22.5%	22.7%	22.4%	23.6%	24.7%	23.9%	14.8%	20.6%	25.1%	22.5%	23.4%	24.4%	25.4%
	c. Total Industry Profits (Production + P/L)	1,351.9	3,034.8	4,429.9	2,789.5	2,915.1	2,371.2	2,126.9	2,707.2	3,495.7	2,692.4	674.0	1,549.1	3,489.9	2,203.0	2,497.4	3,364.3	4,781.8
	Industry Percentage	32.9%	44.4%	46.6%	40.3%	42.5%	42.5%	41.9%	44.0%	46.1%	44.1%	27.6%	37.9%	46.5%	41.5%	43.2%	45.2%	47.0%

Notes:

(See source and calculating notes in Appendix D.)

F. Inflation Adjustment

When compared to the current revenue stream, prior-year values need to be escalated to reflect their greater purchasing power. Therefore, to analyze results over a multi-year span, the effects of inflation need to be considered.[90] Two of the most commonly used measures of inflation are the Consumer Price Index (CPI) and the Gross Domestic Product (GDP) deflator. The effects of both indices on the years under discussion in this report are shown in Figure III.-10. It will be observed that the rate of inflation, as measured by the CPI, is greater than that of the GDP. For example, using the CPI as a benchmark, in 2005 it would take approximately $1.63 to buy goods or services worth $1.00 in 1988; using the GDP as a yardstick, $1.00 in 1988 would equal approximately $1.47 in 2005.[91] In keeping with general practices, this analysis will use the GDP deflator to measure inflation.

In Figure III.-11, the results of the net revenue take analysis for calendar years 1988 through 2004 (Figure III.-9) have been re-cast in real (2005) dollars for comparative analysis. With this adjustment for inflation, the industry take in 2004 (approximately $4.9 billion in 2005 dollars) exceeded by a large margin the industry take in all other years under review except one (1990). At the other end of the price spectrum, at the lowest annual average price recorded (1998), the industry share of the net revenue (approximately $0.8 billion in 2005 dollars) provided investors in North Slope production and pipeline operations with profits of more than $2.1 million per day.

[90] By the same token, future values need to be discounted. Since this analysis is primarily historical, issues involved in future discounting will not be discussed here.

[91] Consumer Price Index – 192.654 / 118.3 = $1.629; Gross Domestic Product deflator – 110.45 / 75.41 = $1.465.

Fig. III.-10. CPI-U and GDP Inflation Indices, 1987 - 2005

(1) Year	(2) U.S. CPI-U (Index)		(3) Inflation (%)	(4) GDP Implicit Price Deflator (Index)		(5) Inflation (%)
1987	113.6000		3.7%	73.1100		2.7%
1988	118.3000		4.1%	75.4100		3.1%
1989	124.0000		4.8%	78.3400		3.9%
1990	130.7000		5.4%	81.2500		3.7%
1991	136.2000		4.2%	84.3000		3.8%
1992	140.3000		3.0%	86.4200		2.5%
1993	144.5000		3.0%	88.3800		2.3%
1994	148.2000		2.6%	90.2800		2.1%
1995	152.4000		2.8%	92.1800		2.1%
1996	156.9000		3.0%	93.9500		1.9%
1997	160.5000		2.3%	95.5900		1.7%
1998	163.0000		1.6%	96.7500		1.2%
1999	166.6000		2.2%	98.0200		1.3%
2000	172.2000		3.4%	100.0000		2.0%
2001	177.1000		2.8%	102.3600		2.4%
2002	179.9000		1.6%	104.2600		1.9%
2003	184.0000		2.3%	106.1400		1.8%
2004	188.9000		2.7%	108.2500		2.0%
2005	192.6540	*	2.0%	110.4500	*	2.0%

Notes:

* Estimated

Col.	**Source (or basis for calculation)**
(2)	1987 - 2005 CPI-U Index from: U.S. Dept. of Labor, Bureau of Labor Statistics; (1987 - 2004 – annual average; 2005 – March 2005 index) Data acquired from: http://data.bls.gov/PDQ/servlet/SurveyOutputServlet (accessed April 26, 2005)
(3)	(Current year Index - Previous year index) / (previous year index) * 100;
(4)	1987 - 2005 GDP Chained Price Index from: U.S. Office of Management and Budget, *The Budget for Fiscal Year 2006,* "Historical Tables," pp. 184-185. Data acquired from: http://www.whitehouse.gov/omb/budget/fy2006/pdf/hist.pdf (Accessed Feb. 26, 2005 [data for 2004-5 corrected Feb. 23, 2005])
(5)	1976-2025: (Current year Index - Previous year index) / (previous year index) * 100;

(Research Associates, April 2005)

Figure III.-11 Revised Estimated Shares of Alaska North Slope Production and Associated Pipeline Revenue (CY 1988 – 2004)

Real (2005)] Dollars *

		Revised Transportation, Production Costs	CY 1988	CY 1989	CY 1990	CY 1991	CY 1992	CY 1993	CY 1994	CY 1995	CY 1996	CY 1997	CY 1998	CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004
(1)		ANS Sales Price ($/Bbl)	$19.80	$24.17	$29.19	$22.73	$22.29	$19.31	$18.60	$20.29	$24.03	$21.93	$14.33	$19.98	$31.24	$25.04	$26.19	$30.84	$39.63
(2)		ANS Production (Million Bbl/Yr)	727.5	698.5	665.9	653.1	636.7	599.8	578.3	558.9	527.4	492.8	448.5	405.2	371.1	362.8	369.7	362.7	343.0
(3)		Gross Production Value (Million $)	14,405.8	16,879.2	19,434.4	14,847.1	14,192.0	11,580.2	10,753.1	11,337.1	12,672.4	10,808.3	6,425.6	8,096.1	11,590.9	9,086.4	9,682.8	11,185.9	13,594.6
(4)		*Calculating Entries*																	
	a.	*Total State and Muni Property Tax*	*518.8*	*499.4*	*459.6*	*446.8*	*426.6*	*398.4*	*385.5*	*370.2*	*355.2*	*339.2*	*336.0*	*305.1*	*291.1*	*286.2*	*286.5*	*279.8*	*271.4*
	b.	*State income tax (Production & P/L)*	*237.3*	*199.6*	*205.5*	*229.7*	*180.9*	*84.6*	*89.5*	*181.0*	*260.5*	*271.2*	*197.0*	*173.4*	*276.6*	*278.7*	*174.5*	*234.1*	*374.9*
	c.	*TAPS State & Fed. Inc. Tax (from tariff)*	*830.0*	*710.4*	*680.6*	*638.6*	*584.1*	*522.6*	*470.6*	*423.6*	*367.9*	*302.9*	*248.1*	*245.0*	*232.1*	*229.6*	*233.2*	*230.9*	*224.0*
(5)		**N. Slope "Feeder" P/L Tariffs**	**95.6**	**92.1**	**88.8**	**85.6**	**81.4**	**60.0**	**56.6**	**53.6**	**49.6**	**51.3**	**51.2**	**50.2**	**49.2**	**50.9**	**121.4**	**135.9**	**161.0**
	a.	*State Subtotal (Feeder)*																	
	b.	*Federal Subtotal (Feeder)*																	
	c.	**Industry Subtotal (Feeder)**	**14.3**	**13.8**	**13.3**	**12.8**	**12.2**	**9.0**	**8.5**	**8.0**	**7.4**	**7.7**	**7.7**	**7.5**	**7.4**	**7.6**	**18.2**	**20.4**	**24.1**
(6)		**Estimated TAPS Tariff**	**3534.7**	**3259.4**	**3199.7**	**2908.0**	**2749.1**	**2412.9**	**2517.1**	**2063.5**	**1780.3**	**1549.9**	**1321.3**	**1242.0**	**1164.0**	**1194.0**	**1292.6**	**1222.7**	**1067.4**
	a.	Operating and capital costs	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	***576.2***	***531.0***	***570.7***	***665.4***	***601.0***	***462.6***
	b.	State and local property tax (TAPS)	103.8	99.9	91.9	89.4	85.3	79.7	77.1	74.0	**81.1**	**77.0**	**73.1**	**69.9**	**68.5**	**64.7**	**60.0**	**60.0**	**60.0**
	c.	State income tax (TAPS)	166.0	142.1	136.1	127.7	116.8	104.5	94.1	84.7	73.6	60.6	49.6	**49.0**	**46.4**	**45.9**	**46.6**	**46.2**	**44.8**
	d.	Federal income tax (TAPS)	664.0	568.4	544.5	510.9	467.2	418.1	376.5	338.9	294.3	242.3	198.5	**196.0**	**185.7**	**183.7**	**186.5**	**184.7**	**179.2**
	e.	After-tax margin	451.4	362.9	411.9	427.3	429.8	400.9	393.9	381.2	363.4	335.2	314.2	**292.1**	**273.1**	**270.1**	**276.3**	**274.5**	**265.9**
	f.	Recovery of deferred return	818.3	726.2	630.3	550.0	464.5	371.1	300.3	244.0	180.7	94.2	56.5	54.8	55.3	55.1	54.2	53.3	52.2
	g.	**DR&R**	**125.1**	**103.2**	**82.5**	**43.5**	**51.5**	**39.0**	**29.8**	**23.1**	**16.2**	**9.7**	**4.4**	**4.1**	**4.0**	**3.7**	**3.4**	**3.0**	**2.7**
(7)		Pipeline Net Revenue Split																	
	a.	State Subtotal (Pipelines)	269.8	242.0	228.1	217.1	202.1	184.2	171.2	158.8	154.7	137.5	122.7	118.9	114.9	110.7	106.6	106.2	104.8
	b.	Federal Subtotal (Pipelines)	664.0	568.4	544.5	510.9	467.2	418.1	376.5	338.9	294.3	242.3	198.5	196.0	185.7	183.7	186.5	184.7	179.2
	c.	**Industry Subtotal (Pipelines)**	**1,352.2**	**1,157.2**	**1,096.7**	**1,006.0**	**927.8**	**797.3**	**713.6**	**640.3**	**554.6**	**435.7**	**373.6**	**349.6**	**331.1**	**327.6**	**332.8**	**329.8**	**319.9**
(8)		**Marine Transportation**	**2,676.6**	**2,006.5**	**1,639.1**	**1,433.6**	**1,266.8**	**975.8**	**978.3**	**930.1**	**925.4**	**809.1**	**717.1**	**748.9**	**713.2**	**736.0**	**681.6**	**596.3**	**560.0**
(9)		**Revised Total Transportation Costs**	**6,307.0**	**5,358.0**	**4,927.6**	**4,427.2**	**4,097.3**	**3,448.7**	**3,552.0**	**3,047.2**	**2,755.3**	**2,410.3**	**2,089.6**	**2,041.1**	**1,926.3**	**1,980.9**	**2,095.6**	**1,954.9**	**1,788.4**
		Transportation Costs ($/bbl.)	**$8.67**	**$7.67**	**$7.40**	**$6.78**	**$6.44**	**$5.75**	**$6.14**	**$5.45**	**$5.22**	**$4.89**	**$4.66**	**$5.04**	**$5.19**	**$5.46**	**$5.67**	**$5.39**	**$5.21**
(10)		Wellhead Revenue	8,098.8	11,521.2	14,506.8	10,419.9	10,094.7	8,131.5	7,201.1	8,289.9	9,917.1	8,398.0	4,336.0	6,054.9	9,664.5	7,105.4	7,587.2	9,231.0	11,806.2
		Wellhead Price ($/bbl.)	$11.13	$16.49	$21.79	$15.95	$15.85	$13.56	$12.45	$14.83	$18.81	$17.04	$9.67	$14.94	$26.04	$19.58	$20.52	$25.45	$34.42
(11)		State ANS Production Revenue	2,695.8	2,819.4	3,419.0	3,158.4	2,792.8	2,258.5	2,051.4	2,125.2	2,264.1	1,904.6	1,335.7	1,669.9	2,015.4	1,720.3	1,810.1	2,060.2	2,425.7
	a.	Royalty	1267.5	1280.7	1570.3	1400.6	1234.0	1002.7	912.5	978.5	1068.9	903.0	620.5	871.9	1124.3	981.8	1104.3	1308.4	1586.4
	b.	Severance Tax	1080.3	1213.1	1563.8	1483.9	1297.1	1013.3	901.3	927.3	996.2	810.0	505.7	618.2	758.7	603.5	565.3	629.1	730.9
	c.	Spill Respons & Conservation Tax	0.3	3.8	3.6	3.2	3.1	3.0	2.8	1.6	1.4	1.3	1.2	0.9	0.9	0.9	0.8	0.8	0.8
	d.	State & local Property Tax (production)	415.0	399.5	367.7	357.4	341.3	318.7	308.4	296.2	284.1	271.4	268.8	244.1	232.9	228.9	229.2	223.9	217.1
	e.	Cook Inlet Revenue (excl. fr. Line [11])	67.3	77.7	86.3	86.7	82.7	79.2	73.6	78.3	86.6	81.1	60.4	65.2	101.4	94.9	89.4	101.9	109.5
(12)		Est. Production Costs (Total)	4,262.1	3,742.2	3,349.2	2,995.1	2,848.2	2,480.9	2,171.8	1,988.8	1,915.7	2,089.9	2,170.9	2,043.0	1,929.6	1,934.7	2,027.4	2,041.7	1,975.3
	a	Est. Production Costs ($/bbl.)	$5.86	$5.36	$5.03	$4.59	$4.47	$4.14	$3.76	$3.56	$3.63	$4.24	$4.84	$5.04	$5.20	$5.33	$5.48	$5.63	$5.76
(13)		Production Net Revenue Split																	
	a.	State Income Tax (Production)	71.3	57.6	69.3	102.0	64.1	-19.9	-4.6	96.3	186.9	210.7	147.4	124.4	230.1	232.7	127.9	187.9	330.1
	b.	Federal Income Tax (Production)	338.1	1,680.8	2,652.1	1,426.3	1,506.5	1,166.3	1,016.9	1,401.9	1,914.3	1,440.5	213.1	751.7	1,897.3	1,103.5	1,246.6	1,708.4	2,455.3
	c.	Industry Profit (Production)	627.9	3,121.4	4,925.3	2,648.8	2,797.8	2,166.0	1,888.5	2,603.5	3,555.1	2,675.3	395.8	1,396.0	3,523.6	2,049.4	2,315.1	3,172.7	4,559.8
(14)		**Production and Pipeline Net Revenue Split:**	**6,019.0**	**9,646.7**	**12,934.9**	**9,069.4**	**8,758.5**	**6,970.5**	**6,213.5**	**7,364.9**	**8,923.9**	**7,046.6**	**2,786.8**	**4,606.5**	**8,298.1**	**5,728.0**	**6,125.7**	**7,750.0**	**10,374.8**
	a.	**Total State Share (Production + P/L)**	**3,036.8**	**3,118.9**	**3,716.4**	**3,477.4**	**3,059.0**	**2,422.8**	**2,218.0**	**2,380.3**	**2,605.6**	**2,252.8**	**1,605.8**	**1,913.2**	**2,360.5**	**2,063.7**	**2,044.6**	**2,354.3**	**2,860.6**
		State Percentage	50.5%	32.3%	28.7%	38.3%	34.9%	34.8%	35.7%	32.3%	29.2%	32.0%	57.6%	41.5%	28.4%	36.0%	33.4%	30.4%	27.6%
	b.	**Federal Revenue**	**1,002.1**	**2,249.1**	**3,196.6**	**1,937.2**	**1,973.8**	**1,584.4**	**1,393.4**	**1,740.8**	**2,208.5**	**1,682.8**	**411.6**	**947.7**	**2,083.0**	**1,287.2**	**1,433.1**	**1,893.1**	**2,634.5**
		Federal Percentage	16.6%	23.3%	24.7%	21.4%	22.5%	22.7%	22.4%	23.6%	24.7%	23.9%	14.8%	20.6%	25.1%	22.5%	23.4%	24.4%	25.4%
	c.	**Total Industry Profits (Production + P/L)**	**1,980.1**	**4,278.6**	**6,022.0**	**3,654.8**	**3,725.7**	**2,963.3**	**2,602.1**	**3,243.8**	**4,109.7**	**3,111.0**	**769.4**	**1,745.6**	**3,854.6**	**2,377.1**	**2,647.9**	**3,502.5**	**4,879.7**
		Industry Percentage	32.9%	44.4%	46.6%	40.3%	42.5%	42.5%	41.9%	44.0%	46.1%	44.1%	27.6%	37.9%	46.5%	41.5%	43.2%	45.2%	47.0%

Notes:

* Revised net revenue split analysis (Fig. III.-9) converted to 2005 dollars using the GDP deflator (Fig. III.-10).

G. Federal Income Tax Effects

One part of this economic picture that requires attention is the effect of federal income taxes. While the technical aspects of separating federal tax payments on TAPS from those on production were observed at the outset, that was only part of the picture regarding federal income taxes; when production costs went up, because costs are deductible, federal taxes on production went down. Nevertheless, the model assumes that all production and pipeline income is taxed at the nominal federal rate of 35 percent. The U.S. Chamber of Commerce instructs that for financial planning, "[y]ou should use your effective tax rate when estimating your total tax liability for a year." By way of explanation, the U.S. Chamber provides the example of an individual who earns $100,000.00 in a year. Although the individual is squarely in the 28% tax bracket, by taking only the standard deductions that are built into the tax code, total tax would add up to $20,401.00, or 20.4% of income. However, the Chamber continues, for purposes of calculating windfalls it is appropriate to estimate the liability on windfalls (as opposed to annual earnings) at the nominal rate.[92]

The U.S. Chamber example is directly analogous to the oil patch. According to international petroleum economic expert Pedro Van Meurs, the vast preponderance of oil investment is incremental. And one of the principal reasons this is the case is that incremental investment dollars are tax advantaged. In other words, he explains, the re-investment of $1.00 of income only costs $0.65 in cash, because it cuts taxes by 35 percent.[93]

Van Meurs treats the additional investment as a marginal dollar that, presumptively, would be taxed at 35 percent. Does this mean that every dollar earned is an incremental dollar? Returning to the U.S. Chamber example: When the individual paid $20,401.00 in taxes on $100,000.00 of income, which dollar of that $100,000.00 of income was taxed at 28%? Assume that half of that income was earned on a second job and was therefore incremental income, taxed at the marginal rate of 28%. In that case, the remaining $50,000 must have been taxed at 12.8% ($6,401 / $50,000 = 12.8%).

Citizens for Tax Justice and the Institute for Taxation and Economic Policy (CTJ/ITEP) reported on effective tax rates paid in 2001 through 2003 by 275 U.S. corporations listed in the *Fortune* "500" that earned a profit in each of those three years. Among their sampling, two of the top 25 recipients of tax breaks were ExxonMobil and ConocoPhillips. CTJ/ITEP calculated that another North Slope company, Anadarko Petroleum, had a negative income tax in 2002 due to rebates and a three-year average effective tax rate of 7.0% Over the three year

[92] U.S. Chamber of Commerce, "Financial Calculators – Marginal and Effective Tax Rates," (http://www.uschamber.com/sb/finance/sohoApplets/TaxMargin.html; accessed March 5, 2005).

[93] Dr. Pedro Van Meurs at "World Fiscal Systems for Oil and Gas.

period, the three North Slope companies and five other profitable petroleum and pipeline companies paid an average effective tax rate of 13.3%.[94] According to CTJ/ITEP, an earlier report that covered 1996 through 1998 found that petroleum and pipeline companies paid an effective tax of 12.3%. In that study, due to low oil prices, the petroleum and pipelines group paid the lowest average effective rate of any industry group. One of the companies that paid a negative income tax due to rebates in 1998 was Phillips (yet to acquire ARCO Alaska or merge with Conoco).[95]

As discussed earlier, ExxonMobil and ConocoPhillips were major tax break recipients through accelerated depreciation, with ConocoPhillips paying effective tax rates of 7.1% and 5.7% in 2001 and 2002. According to CTJ/ITEP calculations, in 2000 ConocoPhillips and ExxonMobil paid effective rates of 25.1% and 27.0%, respectively.[96]

Figure III.-12 displays the effective tax rates reported by CTJ/ITEP for the two major North Slope companies, as well as the weighted average of all companies in the survey.[97]

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[94] *Corporate Income Taxes in the Bush Years,* pp. 4-6, 68. CTJ/ITEP base their results on analysis of reported pre-tax income and actual federal taxes paid, as reported in company annual reports filings with the Securities and Exchange Commission.

[95] Robert S. McIntyre and T.D. Coo Nguyen, *Corporate Income Taxes in the 1990s* (Institute on Taxation and Economic Policy, 2000), pp.2, 5.

[96] The 2000 data are from unpublished work papers provided by CTJ/ITEP. According to McIntyre, “CP (ConocoPhillips) was a pain for some details because of the merger, but the tax and profit figures were straightforward” (personal communication [email], Mar. 10, 2005).

[97] According to CTJ/ITEP, little information on income tax payments by BP is available. Therefore, the weighted average of all petroleum and pipeline companies in the study was applied to BP’s share of the North Slope. (For the 1996-1998 period, Phillips held less than a two percent interest in the North Slope and TAPS and its percentage weighting for calculating the average effective tax rate was reduced accordingly.)

Figure III.-12. Estimates of Effective Federal Income Tax Rates on Alaska North Slope Production and Pipleline Operations, 1996 - 2004

(Effective tax rates for 1996-2003 estimated from ITEP / CTJ data .)

Company	*Approximate Company Percentages of ANS Production & Pipeline Operations*		1996	1997	1998	1999	2000	2001	2002	2003	2004
	1996-1998	2001 -2004									
(1) ExxonMobil (Exxon 1996-1998)	20.00%	20.00%	24.00%	23.80%	10.20%	<n.a.>	27.00%	20.00%	5.30%	15.10%	<n.a.>
(2) ConocoPhillips (Phillips 1996-1998)	1.50%	30.00%	-1.00%	15.30%	-0.70%	<n.a.>	25.10%	7.10%	5.70%	13.00%	<n.a.>
(3) Weighted Avg. Petroleum & Pipeline Companies	80.00%	50.00%	17.20%	11.50%	5.70%	<n.a.>	23.36%	17.30%	5.60%	13.30%	<n.a.>
(4) Approximate Effective Tax Rate (weighted avg.)			**18.56%**	**13.96%**	**6.60%**	**15.60%**	**24.61%**	**14.78%**	**5.57%**	**13.57%**	**25.00%**

Notes:

Estimated effective tax rates from: Robert S. McIntyre (Citizens for Tax Justice) and T.D. Coo Nbuyen (Institute on Taxation and Economic Policy), *Corporate Income Taxes, in the Bush Years* (September 2004) and *Corporate Income Taxes in the 1990s* (October 2000), supplemented by data from Citizens for Tax Justice.

Approximate company percentages of Alaska North Slope and associated pipeline operations from various sources. (Analyzed tax data for BP and ARCO [ConocoPhillips predecessor] were not available. Therefore, their respective shares are estimated as industry averages in Line [3]).

1996-1998: Phillips counted in line (3) with CTJ / ITEP average for 12 petroleum and pipeline companies.

1999: Calculated as average of 1998 and 2000 weighted averages.

2000: ExxonMobil and ConocoPhillips (lines [1] and [2]) from unpublished CTJ / ITEP worksheets; line (3) = (ExxonMobil 2000/2001)* (2001 weighted average of all petroleum and pipeline companies). (Note: ConocoPhillips excluded due to the anomalous tax effects of its 2000 merger and acquisition activities. Applying the ratio of ExxonMobil's 2000 tax rate to its 2001-2003 average would reduce lines [3] and [4] by approximately 0.35% and 0.7%, respectively.)

2001-2003: Line (3) = CTJ / ITEP average of 8 petroleum and pipeline companies.

2004: Estimated at 25% (approximate midpoint between 2003 weighted average estimate of 13.57% and nominal rate of 35%.

(Research Associates, March 2005)

Figures III.-13 and III.-14 apply the weighted average annual effective tax rates calculated in Figure III.-12 to North Slope production and associated pipeline operations during the years 1996 through 2004. These two figures show, respectively, the nominal and inflation-adjusted results of the application of estimated effective tax rates at model Line (13b).

Consideration of the estimated federal income tax effect results in a significant increase to the industry share of the net revenue take, at the expense of the federal government. For example, if one assumes the North Slope producers and their pipeline affiliates paid an effective tax rate of 25% in 2004 (the approximate midpoint between the nominal tax rate and the 2003 estimated weighted average for North Slope production and pipeline companies), their share of the take in 2004 increased from $4.78 billion in nominal dollars to $5.47 billion, with a corresponding decrease in federal revenue.[98] This estimate increases the industry share of the net revenue take for 2004 from 47.0% to 53.8% (see the lower, right-hand corner entries of Figures III.-9 and III.-13, respectively).

Note that effective tax rates further enhance the industry's results during periods of low prices. In 1998 – the year of the lowest average prices in the history of North Slope operations – if the companies operating on the North Slope paid the effective tax rates calculated in Figure III.-12, their share of the net revenue take would have increased significantly, from 27.6% shown in Figures III.-9 and III.-11 to 33.8% in Figures III.-13 and III.-14.

[98] From this result, it can be inferred that at current prices and production a 1.0% reduction in the effective tax rate increases industry take by approximately $70.0 million.

Figure III.-13. Revised Estimated Shares with Effective Income Tax Rate (CY 1996 – CY 2004)

Nominal Dollars

	Estimated Effective Federal Income Tax Rates	CY 1996	CY 1997	CY 1998	CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004
(1)	ANS Sales Price ($/Bbl)	$20.44	$18.98	$12.55	$17.73	$28.28	$23.21	$24.72	$29.64	$38.84
(2)	ANS Production (Million Bbl/Yr)	527.4	492.8	448.5	405.2	371.1	362.8	369.7	362.7	343.0
(3)	Gross Production Value (Million $)	10,779.3	9,354.1	5,628.6	7,184.9	10,494.2	8,420.8	9,140.1	10,749.4	13,323.8
(4)	*Calculating Entries*									
	a. Total State and Muni Property Tax	*302.1*	*293.6*	*294.3*	*270.8*	*263.6*	*265.2*	*270.4*	*268.9*	266.0
	b. State income tax (Production & P/L)	*221.6*	*234.8*	*172.6*	*153.9*	*250.4*	*258.3*	*164.8*	*225.0*	*367.4*
	c. TAPS State & Fed. Inc. Tax (from tariff)	*312.9*	*262.1*	*217.3*	**217.4**	**210.1**	**212.8**	**220.1**	**221.9**	**219.5**
(5)	N. Slope "Feeder" P/L Tariffs	42.2	44.4	44.8	44.6	44.5	47.2	114.6	130.6	157.8
	a. State Subtotal (Feeder)									
	b. *Federal Subtotal (Feeder)*									
	c. Industry Subtotal (Feeder)	6.3	6.7	6.7	6.7	6.7	7.1	17.2	19.6	23.7
(6)	Estimated TAPS Tariff	1514.3	1341.4	1157.4	1102.3	1053.9	1106.6	1220.2	1175.0	1046.2
	a. Operating and capital costs	*n.a.*	*n.a.*	*n.a.*	**511.3**	**480.7**	**528.9**	**624.8**	**575.2**	**452.2**
	b. **State and local property tax (TAPS)**	**69.0**	**66.6**	**64.0**	**62.0**	**62.0**	**60.0**	**60.0**	**60.0**	**60.0**
	c. State income tax (TAPS)	62.6	52.4	43.5	**43.5**	**42.0**	**42.6**	**44.0**	**44.4**	**43.9**
	d. Federal income tax (TAPS)	250.3	209.7	173.8	**174.0**	**168.1**	**170.2**	**176.1**	**177.5**	**175.6**
	e. After-tax margin	309.1	290.1	275.2	**259.3**	**247.3**	**250.3**	**260.8**	**263.8**	**260.6**
	f. Recovery of deferred return	153.7	81.5	49.5	48.6	50.1	51.1	51.2	51.2	51.2
	g. DR&R	13.8	8.4	3.9	3.6	3.7	3.5	3.2	2.9	2.6
(7)	Pipeline Net Revenue Split									
	a. State Subtotal (Pipelines)	131.6	119.0	107.5	105.5	104.0	102.6	104.0	104.4	103.9
	b. Federal Subtotal (Pipelines)	250.3	209.7	173.8	174.0	168.1	170.2	176.1	177.5	175.6
	c. Industry Subtotal (Pipelines)	471.8	377.1	327.2	310.2	299.7	303.6	314.1	316.9	313.5
(8)	Marine Transportation	787.2	700.3	628.1	664.6	645.7	682.1	643.4	573.0	548.8
(9)	Revised Total Transportation Costs	2,343.7	2,086.0	1,830.4	1,811.4	1,744.1	1,835.8	1,978.1	1,878.6	1,752.8
	Transportation Costs ($/bbl.)	$4.44	$4.23	$4.08	$4.47	$4.70	$5.06	$5.35	$5.18	$5.11
(10)	Wellhead Revenue	8,435.6	7,268.1	3,798.2	5,373.5	8,750.1	6,585.0	7,162.0	8,870.8	11,571.1
	Wellhead Price ($/bbl.)	$16.00	$14.75	$8.47	$13.26	$23.58	$18.15	$19.37	$24.46	$33.73
(11)	State ANS Production Revenue	1,925.8	1,648.4	1,170.0	1,482.0	1,824.7	1,594.3	1,708.7	1,979.8	2,377.4
	a. Royalty	909.2	781.5	543.5	773.8	1017.9	909.9	1042.4	1257.4	1554.8
	b. Severance Tax	847.4	701.0	443.0	548.6	686.9	559.3	533.6	604.5	716.4
	c. Spill Respons & Conservation Tax	1.2	1.2	1.0	0.8	0.8	0.8	0.8	0.8	0.7
	d. State & local Property Tax (production)	241.7	234.9	235.4	216.6	210.9	212.2	216.3	215.1	212.8
	e. Cook Inlet Revenue (excl. fr. Line [11])	73.7	70.2	52.9	57.9	91.8	87.9	84.4	97.9	107.3
(12)	Est. Production Costs (Total)	1,629.6	1,808.7	1,901.6	1,813.0	1,747.1	1,793.0	1,913.8	1,962.0	1,935.9
	a Est. Production Costs ($/bbl.)	$3.09	$3.67	$4.24	$4.47	$4.71	$4.94	$5.18	$5.41	$5.64
(13)	Production Net Revenue Split									
	a. State Income Tax (Production)	159.0	182.3	129.1	110.4	208.4	215.7	120.7	180.6	323.5
	b. Federal Income Tax (Production)	**863.5**	**497.3**	**35.2**	**297.3**	**1,207.9**	**431.9**	**187.1**	**636.2**	**1,718.5**
	c. Industry Profit (Production)	3,788.8	3,064.8	498.2	1,608.7	3,700.1	2,490.2	3,171.7	4,052.1	5,155.6
(14)	**Production and Pipeline Net Revenue Split:**	**7,590.7**	**6,098.6**	**2,441.1**	**4,088.1**	**7,513.0**	**5,308.4**	**5,782.4**	**7,447.5**	**10,168.2**
	a. Total State Share (Production + P/L)	**2,216.4**	**1,949.7**	**1,406.6**	**1,697.9**	**2,137.1**	**1,912.5**	**1,933.4**	**2,264.8**	**2,804.8**
	State Percentage	29.2%	32.0%	57.6%	41.5%	28.4%	36.0%	33.4%	30.4%	27.6%
	b. Federal Revenue	**1,113.8**	**707.0**	**209.0**	**471.3**	**1,376.0**	**602.1**	**363.2**	**813.7**	**1,894.2**
	Federal Percentage	14.7%	11.6%	8.6%	11.5%	18.3%	11.3%	6.3%	10.9%	18.6%
	c. Total Industry Profits (Production + P/L)	**4,260.6**	**3,441.9**	**825.4**	**1,918.9**	**3,999.9**	**2,793.8**	**3,485.8**	**4,369.0**	**5,469.2**
	Industry Percentage	56.1%	56.4%	33.8%	46.9%	53.2%	52.6%	60.3%	58.7%	53.8%

Notes:

This figure revises Figure III.-9 at Line (13a) per Fig. III.-12.

Figure III.-14. Revised Estimated Shares with Effective Income Tax Rate (CY 1996 – CY 2004)

Real (2005) Dollars

	Estimated Effective Federal Income Tax Rates	CY 1996	CY 1997	CY 1998	CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004
(1)	ANS Sales Price ($/Bbl)	$24.03	$21.93	$14.33	$19.98	$31.24	$25.04	$26.19	$30.84	$39.63
(2)	ANS Production (Million Bbl/Yr)	527.4	492.8	448.5	405.2	371.1	362.8	369.7	362.7	343.0
(3)	Gross Production Value (Million $)	12,672.4	10,808.3	6,425.6	8,096.1	11,590.9	9,086.4	9,682.8	11,185.9	13,594.6
(4)	*Calculating Entries*									
	a. Total State and Muni Property Tax	*355.2*	*339.2*	*336.0*	*305.1*	*291.1*	*286.2*	*286.5*	*279.8*	*271.4*
	b. State income tax (Production & P/L)	*260.5*	*271.2*	*197.0*	*173.4*	*276.6*	*278.7*	*174.5*	*234.1*	*374.9*
	c. TAPS State & Fed. Inc. Tax (from tariff)	*367.9*	*302.9*	*248.1*	*245.0*	*232.1*	*229.6*	*233.2*	*230.9*	*224.0*
(5)	N. Slope "Feeder" P/L Tariffs	*49.6*	*51.3*	*51.2*	*50.2*	*49.2*	*50.9*	*121.4*	*135.9*	*161.0*
	a. *State Subtotal (Feeder)*									
	b. *Federal Subtotal (Feeder)*									
	c. Industry Subtotal (Feeder)	7.4	7.7	7.7	7.5	7.4	7.6	18.2	20.4	24.1
(6)	Estimated TAPS Tariff	1780.3	1549.9	1321.3	1242.0	1164.0	1194.0	1292.6	1222.7	1067.4
	a. Operating and capital costs	*n.a.*	*n.a.*	*n.a.*	576.2	531.0	570.7	661.9	598.6	461.4
	b. State and local property tax (TAPS)	81.1	77.0	73.1	69.9	68.5	64.7	63.6	62.4	61.2
	c. State income tax (TAPS)	73.6	60.6	49.6	49.0	46.4	45.9	46.6	46.2	44.8
	d. Federal income tax (TAPS)	294.3	242.3	198.5	196.0	185.7	183.7	186.5	184.7	179.2
	e. After-tax margin	363.4	335.2	314.2	292.1	273.1	270.1	276.3	274.5	265.9
	f. Recovery of deferred return	180.7	94.2	56.5	54.8	55.3	55.1	54.2	53.3	52.2
	g. DR&R	16.2	9.7	4.4	4.1	4.0	3.7	3.4	3.0	2.7
(7)	Pipeline Net Revenue Split									
	a. State Subtotal (Pipelines)	154.7	137.5	122.7	118.9	114.9	110.7	110.2	108.6	106.0
	b. Federal Subtotal (Pipelines)	294.3	242.3	198.5	196.0	185.7	183.7	186.5	184.7	179.2
	c. Industry Subtotal (Pipelines)	554.6	435.7	373.6	349.6	331.1	327.6	332.8	329.8	319.9
(8)	Marine Transportation	925.4	809.1	717.1	748.9	713.2	736.0	681.6	596.3	560.0
(9)	Revised Total Transportation Costs	2,755.3	2,410.3	2,089.6	2,041.1	1,926.3	1,980.9	2,095.6	1,954.9	1,788.4
	Transportation Costs ($/bbl.)	$5.22	$4.89	$4.66	$5.04	$5.19	$5.46	$5.67	$5.39	$5.21
(10)	Wellhead Revenue	9,917.1	8,398.0	4,336.0	6,054.9	9,664.5	7,105.4	7,587.2	9,231.0	11,806.2
	Wellhead Price ($/bbl.)	$18.81	$17.04	$9.67	$14.94	$26.04	$19.58	$20.52	$25.45	$34.42
(11)	State ANS Production Revenue	2,264.1	1,904.6	1,335.7	1,669.9	2,015.4	1,720.3	1,810.1	2,060.2	2,425.7
	a. Royalty	1068.9	903.0	620.5	871.9	1124.3	981.8	1104.3	1308.4	1586.4
	b. Severance Tax	996.2	810.0	505.7	618.2	758.7	603.5	565.3	629.1	730.9
	c. Spill Respons & Conservation Tax	1.4	1.3	1.2	0.9	0.9	0.9	0.8	0.8	0.8
	d. State & local Property Tax (production)	284.1	271.4	268.8	244.1	232.9	228.9	229.2	223.9	217.1
	e. Cook Inlet Revenue (excl. fr. Line [11])	86.6	81.1	60.4	65.2	101.4	94.9	89.4	101.9	109.5
(12)	Est. Production Costs (Total)	1,915.7	2,089.9	2,170.9	2,043.0	1,929.6	1,934.7	2,027.4	2,041.7	1,975.3
	a Est. Production Costs ($/bbl.)	$3.63	$4.24	$4.84	$5.04	$5.20	$5.33	$5.48	$5.63	$5.76
(13)	Production Net Revenue Split									
	a. State Income Tax (Production)	186.9	210.7	147.4	124.4	230.1	232.7	127.9	187.9	330.1
	b. Federal Income Tax (Production)	**1,015.1**	**574.6**	**40.2**	**335.0**	**1,334.1**	**466.0**	**198.2**	**662.0**	**1,753.5**
	c. Industry Profit (Production)	4,454.2	3,541.3	568.8	1,812.7	4,086.8	2,687.0	3,360.0	4,216.7	5,260.4
(14)	**Production and Pipeline Net Revenue Split:**	**8,923.9**	**7,046.6**	**2,786.8**	**4,606.5**	**8,298.1**	**5,728.0**	**6,125.7**	**7,750.0**	**10,374.8**
	a. Total State Share (Production + P/L)	**2,605.6**	**2,252.8**	**1,605.8**	**1,913.2**	**2,360.5**	**2,063.7**	**2,048.2**	**2,356.8**	**2,861.8**
	State Percentage	29.2%	32.0%	57.6%	41.5%	28.4%	36.0%	33.4%	30.4%	27.6%
	b. Federal Revenue	**1,309.4**	**816.9**	**238.6**	**531.1**	**1,519.7**	**649.7**	**384.7**	**846.8**	**1,932.7**
	Federal Percentage	14.7%	11.6%	8.6%	11.5%	18.3%	11.3%	6.3%	10.9%	18.6%
	c. Total Industry Profits (Production + P/L)	**5,008.8**	**3,976.9**	**942.3**	**2,162.3**	**4,417.9**	**3,014.6**	**3,692.8**	**4,546.4**	**5,580.3**
	Industry Percentage	56.1%	56.4%	33.8%	46.9%	53.2%	52.6%	60.3%	58.7%	53.8%

Notes:

This figure adjusts Fig. III.-13 for inflation using the GDP deflator (Fig. III.-10).

H. Conclusions

Figure III.-15 summarizes the estimated results of North Slope production and associated pipeline operations since 1996 in real (2005) dollars. These calculations indicate that since 1996 the industry has retained, on average, 54.1% of total net revenue, compared to 32.6% for the state and 13.4% for the federal government. Industry share of the net revenue take exceeded 50 percent in seven of the last nine years. By comparison, in the ADOR net take summary that served as the starting point for this analysis, the industry share of the net revenue take never exceeded 45%.

Note that the estimated state share, relative to industry, appears to grow smaller as prices increase. For example, the 2004 results show that the industry share of the net revenue take was nearly twice that of the state of Alaska. The state share in 2004 – 27.6% at an inflation-adjusted price of $39.63 per barrel in 2005 dollars – was significantly less than the nine-year average state take of 32.6% at an inflation-adjusted average price of $25.91.[99]

In 2004, industry's estimated net revenue take was approximately $15.0 million per day in nominal dollars ($15.3 million in 2005 dollars), compared to state take of $7.7 million nominal ($7.8 million in 2005 dollars).

[99] For historical trending purposes, the inflation-adjusted figures provide a more useful basis for analysis than nominal figures.

Fig. III.-15. Estimated Shares of Alaska N. Slope Production and Associated Pipeline Net Revenue, 1996 - 2004

Nominal Dollars

	1996	1997	1998	1999	2000	2001	2002	2003	2004	Totals
ANS West Coast Average Price ($/bbl.)	$20.44	$18.98	$12.55	$17.73	$28.28	$23.21	$24.72	$29.64	$38.84	$23.82
Total Production and P/L Net Revenue ($ Millions)	7,590.7	6,098.6	2,441.1	4,088.1	7,513.0	5,308.4	5,782.4	7,447.5	10,168.2	56,438.1
Total State Share (Production + P/L)	2,216.4	1,949.7	1,406.6	1,697.9	2,137.1	1,912.5	1,933.4	2,264.8	2,804.8	18,323.3
State Percentage	29.2%	32.0%	57.6%	41.5%	28.4%	36.0%	33.4%	30.4%	27.6%	32.5%
Federal Revenue	1,113.8	707.0	209.0	471.3	1,376.0	602.1	363.2	813.7	1,894.2	7,550.2
Federal Percentage	14.7%	11.6%	8.6%	11.5%	18.3%	11.3%	6.3%	10.9%	18.6%	13.4%
Total Industry Profits (Production + P/L)	4,260.6	3,441.9	825.4	1,918.9	3,999.9	2,793.8	3,485.8	4,369.0	5,469.2	30,564.5
Industry Percentage	56.1%	56.4%	33.8%	46.9%	53.2%	52.6%	60.3%	58.7%	53.8%	54.2%

Real (2005) Dollars

	1996	1997	1998	1999	2000	2001	2002	2003	2004	Totals
ANS West Coast Average Price ($/bbl.)	$24.03	$21.93	$14.33	$19.98	$31.24	$25.04	$26.19	$30.84	$39.63	$25.91
Total Production and P/L Net Revenue ($ Millions)	8,923.9	7,046.6	2,786.8	4,606.5	8,298.1	5,728.0	6,125.7	7,750.0	10,374.8	61,640.4
State Share (Production + P/L)	2,605.6	2,252.8	1,605.8	1,913.2	2,360.5	2,063.7	2,048.2	2,356.8	2,861.8	20,068.4
State Percentage	29.2%	32.0%	57.6%	41.5%	28.4%	36.0%	33.4%	30.4%	27.6%	32.6%
Federal Revenue	1,309.4	816.9	238.6	531.1	1,519.7	649.7	384.7	846.8	1,932.7	8,229.6
Federal Percentage	14.7%	11.6%	8.6%	11.5%	18.3%	11.3%	6.3%	10.9%	18.6%	13.4%
Industry Profits (Production + P/L)	5,008.8	3,976.9	942.3	2,162.3	4,417.9	3,014.6	3,692.8	4,546.4	5,580.3	33,342.4
Industry Percentage	56.1%	56.4%	33.8%	46.9%	53.2%	52.6%	60.3%	58.7%	53.8%	54.1%

Notes:

Based on reported spot market price for Alaska North Slpe crude oil, actual state revenue as reported by the Alaska Department of Revenue and estimated effective tax rates from Citizens for Tax Justice / Institute on Taxation and Economic Policy reports. Annual results converted to 2005 dollars using the GDP deflator.

(From Figures III.-13 and III.-14; see discussion in text.)

The model developed here, which relies on the fixed landmarks of reported oil prices and publicly available state petroleum receipts, is not designed for forecasting. Nevertheless, with additional calculations its results can be used to estimate results for the current calendar year. Combining the ADOR forecast price for fiscal years 2005 and 2006 results in an average price of approximately $40.00 per barrel. Using the current net revenue split as the basis for dividing additional revenue, a $1.00 per barrel price increase would add approximately $54 million to the industry share, compared to $27 million for the state and $19 million for the federal government.[100] ADOR calculates that at $40.00 per barrel the revisions to the severance tax Economic Limit Factor (ELF) instituted by the governor will add approximately $178 million to the state share of the net revenue take, with resulting decreases to the industry and federal shares of approximately $115 million and $62 million, respectively.[101] These calculations would result in an industry net revenue take of approximately $5.41 billion for 2005, leaving $3.01 billion for the state and 1.85 billion for the federal government. Thus, the industry's share of the net revenue take would be approximately 52.7%, compared to 29.3% for the state and 18.0% for the federal government. In sum, even with the ELF revision instituted by the governor, for every dollar the state receives on Alaska operations at forecast prices the industry will earn nearly $2.00 and will retain more than 50 percent of the total net revenue take for the eighth time in ten years.

Put otherwise, at an average price of $40.00 per barrel, in 2005 the industry will earn a tax-paid profit of approximately $14.8 million per day on its Alaska production and pipeline operations. Using this revenue split, at $50.00 per barrel the industry is making approximately $15.5 million per day.

It should be noted that these estimates of profitability do not include: (1) marine or downstream profits;[102] (2) the benefits to the vertically integrated major North Slope producers of a stable supply of oil for their West Coast refineries; (3) the value of retained DR&R funds previously collected through the TAPS tariff;[103] or (4) cash flow items such as depreciation collected through the TAPS tariff.[104]

[100] No adjustment is made here for production or excess TAPS tariff collections. For this rough approximation, it is assumed that North Slope production will equal that of 2004. In fact, however, ADOR forecasts a slight increase to the production level shown in this estimate. Based on the Regulatory Commission of Alaska's finding that TAPS tariffs provide a just and reasonable profit at $1.96 per barrel, no adjustment is made to account for the increase in the filed TAPS tariff from approximately $3.05 per barrel in 2004 to $3.72 in 2005 (see discussion in Sec. III.C., above).

[101] Estimated from Alaska Department of Revenue February 2005 ELF analysis for Rep. Les Gara.

[102] See discussion of crude oil pricing in Section III.B, above.

[103] A small portion of DR&R collections through the TAPS tariff is displayed in Figure III.-9 at Line (6g).

[104] See Figure III.-4, above.

To enable concerned citizens to evaluate for themselves the profitability and economic viability of North Slope production and associated pipeline operations, this report places a premium on using data that are readily accessible to the general public. In the process of developing this information, several areas have been identified where better public information is needed.

- Despite the fact that TAPS tariffs are filed annually and are public, due to the complexity of the tariff methodology, without additional information that summary information is of little use. Unfortunately, critical information necessary to analyze TAPS tariffs is deemed confidential. The various public policy deliberations regarding TAPS tariffs underscore the need for better public information in this area.

- This analysis also documented the importance of the distinction between nominal and effective income tax rates. Again, in the absence of substantive information, publicly available estimating factors were used. As indicated in Figures III.-9 and III.-13, if the production and pipeline companies that ship oil through Valdez paid an effective federal income tax rate of 25% in 2004 instead of the nominal 35% rate,[105] the result would be an increase in industry take of nearly $700.0 million.

- The utility of the conversion to calendar year data was immediately apparent in replacing fiscal year 2004 data, based on oil at $31.74 per barrel, with calendar year information showing the division of the net revenue take at $38.84 per barrel – a price term with much greater relevance to oil prices in 2005 than the fiscal year 2004 price. The calendar year framework provides a better basis for comparison with government and industry reports. Unfortunately, however, the conversion process was often time-consuming and problematical, again due to lack of public data.

In each of these areas, public officials should be able to compile aggregate data that could be released to the general public without revealing either taxpayer-specific information or proprietary information that might impair a company's competitive position.

The model also identifies the need for better information regarding other factors that might impair the economic viability of continued North Slope oil development. These include the increasing costs associated with field development and production and feeder pipeline tariffs. Both factors have been incorporated into the model results and neither appears to threaten the viability of

[105] As discussed in Section III.G, above, a 25% effective federal income tax rate approximates the midpoint between the effective rate of 13.57% reportedly paid by selected North Slope production and pipeline companies in 2003 and the nominal 35% rate.

North Slope petroleum development at this time. Nevertheless, factors such as these warrant understanding and continued monitoring.

Another important issue that emerged from this analysis is the need for better understanding of the North Slope's economic performance when oil prices are low. It is frequently asserted that the possibility of low oil prices detracts from the long-term economic prospects for North Slope development, In this regard, however, three points are noteworthy:

Even when oil prices crash for extended periods, the North Slope continues to generate profits for its investors. The 17-year period studied in this report included two episodes of low prices; North Slope operations continued to operate profitably during both periods.. This stellar performance sets the North Slope apart from most business enterprises and calls into question the notion that North Slope development is a risky venture. Consider in this regard the performance of three of the firms among the small group that has shared the number one position on the *Fortune* "500" profits list with ExxonMobil: General Motors, IBM and Ford. Within a short period from the time they were at the pinnacle, each experienced dramatic falls, losing money for at least two years in a row as their stock values plummeted.[106] In contrast, in the worst of times the North Slope and TAPS generate more than $1,000.00 per minute in profits for the three major owners of the North Slope production and TAPS and their junior partners.[107] In this regard, two of the factors mentioned above come into play: TAPS profits at low prices provided more than half of the estimated $674.0 million nominal profits from North Slope production and pipelines in 1998, while reduced effective income tax rates shrink the federal tax bite at low prices.[108]

In sum, this analysis of annual results from North Slope production and associated pipeline operations confirms the generally positive conclusions of the 2004 Wood Mackenzie report and the favorable comparison in the ConocoPhillips annual report between Alaska and other regions discussed in Section II.

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[106] For example, General Motors ranked first in profits in 1995 but reported losses in 1991 and 1992; IBM ranked first in profits in 1990 but lost money from 1991 through 1993; Ford ranked first in profits in 1994 but lost money in 1991 and 1992 (*Fortune* "500," various years).

[107] In 1998 the North Slope production and associated pipeline operations generated an estimated $674 million in profits (Figure III.-9 [nominal dollars, taxed at 35%]) to $942 million (Figure III.-13 [inflation-adjusted dollars, taxed at 25%]). $674,000,000 / 525,960 = $1,281.00 / minute; $942,000,000 / .525,960 = $1,791.).

[108] See Figures III.-9, Lines (6) and (14) and III.-14 at Lines (6), (13b) and (14).

IV. CONCLUSIONS AND RECOMMENDATIONS

A. Conclusions

The following principal conclusions emerge from the analysis of North Slope oil production and associated pipeline operations in this report:

1. Economic Viability of the North Slope and TAPS

Two different types of economic analysis confirm that Alaska North Slope (ANS) petroleum operations and the Trans-Alaska Pipeline System (TAPS), despite reduced production during the last two decades, combine to form a business venture that continues to be profitable to investors and competitive in the international arena.

a. Long-Term Financial Analysis (Section II)

Independent industry and corporate financial reports indicate that the North Slope continues to be competitive with other petroleum provinces. In this regard, two conclusions are of particular interest:

- In a review of the operations of approximately sixty international petroleum provinces, the international consulting firm Wood Mackenzie found that despite its relatively high costs (including pipeline operations), Alaska ranks in the top quartile in terms of value per barrel to the industry, while terms offered by government generally ranks in the top half from a company perspective.

- Under standardized reporting requirements, ConocoPhillips reports a better return on past Alaska exploration and development investment than it earns on similar investments elsewhere in the world.

b. Annual Net Revenue Analysis (Section III)

Analysis of net revenue take from North Slope production and associated pipelines confirms the steady profitability of these operations. Among the results of this analysis:

- When ANS averaged $38.84 in 2004, the industry net revenue take on North Slope production and associated pipeline operations (including TAPS) was approximately $15.0 million per day in nominal dollars (unadjusted for inflation), or 53.8% of the total net revenue take. By comparison, the state received $7.7 million (27.6%) and federal take was $5.2 million (18.6%).

- Between 1996 and 2004, industry retained more than half of the net revenue take – 54.1%, compared to 32.6% received by the state of Alaska and 13.4% by the federal government. If oil prices remain at or near $40.00 per barrel through 2005, the industry will retain more than half of the net revenue take from North Slope and associated pipeline operations for the eighth time in the past 10 years.

- The model used in this analysis indicates that the industry will earn approximately $14.8 million per day at an average price of $40.00 per barrel in 2005; when prices are at $50.00 per barrel, the industry net revenue take increases to approximately $15.5 million per day.

- When oil prices averaged $12.55 per barrel (nominal) in 1998, industry profits on North Slope production and pipeline operations were $2.3 million per day ($2.6 million per day at $14.33 per barrel in 2005 dollars). The fact that the North Slope remains profitable at low prices sets this enterprise apart, as a business concern, from national profit leaders such as IBM, General Motors and Ford, which lose money in bad years.

- This analysis indicates that the operators of the North Slope oil fields and the TAPS take a significantly larger share of the take than indicated by a similar analysis by the Alaska Department of Revenue (ADOR), primarily due to the use of estimated effective federal income tax rates instead of the nominal 35% rate used by ADOR.

2. Better Public Data Needed

Confusion about how Alaska's petroleum fiscal regime stacks up against the terms offered by the host governments of other petroleum provinces and the difficulties acquiring the data necessary to conduct the analysis of Alaska's net revenue take were discussed in Sections II. and III. Both problems demonstrate that better public information is needed to improve public understanding of Alaska North Slope petroleum operations and the intricate relationships between industry and government regulators, including revenue collectors. These recommendations follow.

B. Recommendations to Improve Public Information on North Slope Petroleum Development

This group of recommendations constitutes a call for improvements in the public information essential to the formulation of public policy on petroleum development. These proposals do not represent changes in substantive policies; rather, they represent a contribution to the process of making and reviewing those policies. These recommendations are grounded in the difficulties encountered in obtaining the data necessary for this analysis and the assumption that timely release of comprehensive, aggregate information about the economics of North Slope production and associated pipeline operations can make an important contribution to the public policy dialogue on petroleum development without infringing on corporate competitive interests or their taxpayer confidentiality: The issues identified here can be separated into two groups:

1. information already gathered by public officials that can be aggregated to provide comprehensive information for public release; and

2. information that is needed on specific issues relevant to the course of future North Slope oil development.

<u>1. Aggregate, Comprehensive Information</u>

The publication by state agencies of information about public revenue is a well-established principle grounded in the citizen's right to the fullest disclosure possible about matters of public policy. This report has identified three areas in which aggregated, comprehensive information can make an important contribution to the public policy dialogue on petroleum development. One – the release of calendar-year financial data – is a clerical matter. The other two require balancing between the public right to know and corporate claims to confidentiality, based on individual rights to privacy. These three recommendations, linked by virtue of their importance to the public policy dialogue on petroleum development, share the premise that the release of aggregated, comprehensive data will lead to more informed – and, consequently, better – public policy decisions without disclosing privileged information.

a. Calendar Year Data

The Alaska Department of Revenue (ADOR) reports petroleum revenue information primarily on a state fiscal year basis. As discussed in Section II.B, by formatting aggregate data public data on a calendar-year basis, ADOR can provide members of the public with information that will provide a better basis for comparing information about the North Slope economic performance with federal agency reports, corporate data and press reports.

b. Federal Income Tax Rates

State estimates of the division of net petroleum and pipeline revenue between the industry and government are based on an assumption that companies pay the nominal federal income tax rate (35%). But companies often pay a lower effective tax rate due to deductions for accelerated depreciation, consolidated income tax returns and other provisions that reduce the standard tax bite. Corporate tax breaks affect the petroleum take in at least three significant ways:

- *<u>Nominal v. Effective Rates</u>.* Because federal income tax is paid after all payments to the state are made, reductions in federal increase the company take on a dollar-for-dollar basis but do not diminish the state's share. If companies paid 25% effective rate in 2004, the industry share of the North Slope production and pipeline take would have increased by abut $700 million (nominal) over estimates based on the 35% rate, boosting the industry take from about 47.0% to 53.8%

- *Low Prices.* As shown in Figures III.-9 and III.-13 (Lines [13c] and [14c], federal tax breaks allow oil companies to earn higher (although still reduced) profits when oil prices are low than the profits indicated by estimates based on the 35% tax rate.
- *Effect on Industry Percentage Take.* While federal tax breaks do not directly reduce state revenue, these breaks enable North Slope producers to increase profits without sharing those gains with their state partner in development.

While ADOR cannot release taxpayer specific information, it may be possible for the department to use a methods and information similar to those employed in Section III.G to provide the public with information on estimated aggregate tax payments without revealing specific taxpayer information.

c. TAPS Tariffs

Expenditures to ensure safe operations and maximum environmental protection at the VMT and in Prince William Sound are funded through the TAPS tariff. In turn, that tariff has significant effects on the economics of North Slope petroleum development. To the extent that economic considerations drive safety and environmental decisions, It follows, therefore, that clear understanding of the economic implications of TAPS tariffs can make an important contribution to a more informed – and, consequently, better – public policy dialogue on these issues. Unfortunately, all but the fundamental outlines of these important issues are obscured by a cloak of confidentiality. Every dollar the TAPS owners spend on environmental improvements reduces their state their royalty and severance payments by $0.19 (see Section III.C at page 35). This fact, however, does not provide a comprehensive picture of the implications of safety and environmental expenditures on TAPS. The following observations demonstrate the importance of understanding the full economic context of these expenditures:

- The Regulatory Commission of Alaska has found that TAPS Owners have charged excessive tariffs. As indicated above, every dollar in TAPS tariffs reduces state royalty and severance receipts by $0.19). At forecast throughput rates, a TAPS overcharge of $1.00 per barrel, at forecast throughput rates these overcharge would reduce state revenue by more than $60 million per year. Most of the excess goes to the three major owners of the pipeline, who charge themselves (and other users) a full tariff, which includes significant profit elements.

- The TAPS tariff per-barrel profit allowance provides TAPS owners with a hedge against low oil prices (see the results for 1998 in Figure III.-9 at lines [7c] and [14c]).

- Tariffs also function to handicap competition from non-owners shippers. Unlike the TAPS owners, who are paying themselves, non-owner shippers pay all tariff costs out of pocket.

- To understand this picture, the state's position on TAPS tariffs over the past 25 years also must be considered. Having opposed tariff reductions before the RCA, in 2004 the state joined shipper Anadarko Petroleum in opposing current tariffs before the Federal Energy Regulatory Commission.

Although the tariffs significantly impact the total net revenue take, these effects cannot be estimated with confidence because summary data on TAPS tariffs, formerly public, are no longer available for public review. The release of aggregate information on the elements of the TAPS tariff, discussed in Section III.C, can make a significant contribution to understanding the economic factors affecting environmental expenditures through TAPS.

2. Other Petroleum Policy Issues

In the course of gathering information for this project and creating the estimates of profitability presented here, other important issues relevant to the commercial viability of North Slope development were identified. In each case, better information would elevate the public policy dialogue on these significant issues.

a. The Price Term

As the starting point for setting the value of a barrel of crude oil, the price term is a critical factor. Because the major ANS producers transfer most of their oil to their own affiliates, the market price must be derived from other transactions and must be regarded as somewhat problematical. The history of royalty and tax disputes over ANS value demonstrates that the price term is subject to manipulation. For this reason, it is noteworthy that California's controller, in his claim that California crude oil producers may be reporting artificially low prices to reduce their royalty payments in California, suggests that ANS may face a similar valuation problem (see Section III.B). The threat of low oil prices is frequently cited as a reason why the industry is entitled to a disproportionate share of the take during periods of high oil prices. Because there is less net revenue to share when oil prices are depressed, accurate reporting of the price term is also important during those periods.

b. Operating and Capital Costs

As discussed in Section III.D, the operating and capital costs for new and aging fields are critical factors with significant effects on North Slope development. In this regard, it should be noted that the Alaska Department of Revenue forecasts that heavy oil production will double between 2005 and 2010, when it will comprise nearly one-fifth of all North Slope production. In view of the increasingly important role of heavy oil, the costs of production and development and the implications for handling on the pipeline should be carefully monitored.

c. North Slope Feeder Pipeline Tariffs

Although precise data were not developed, Alaska Department of Revenue data indicate North Slope feeder pipeline tariffs – an additional charge levied by field developers to transport oil from remote fields to TAPS at Pump Station #1 – have increased significantly in recent years as a greater percentage of North Slope production comes from remote fields. Feeder pipeline costs constitute a potential barrier to development, as well as a source of revenue to their operators and a means to reduce state royalty and severance payments. Therefore, in order to understand the profitability of North Slope development and its associated pipelines, these costs should be closely monitored.

d. Severance Tax Economic Limit Factor (ELF)

Through the efforts of legislators and informed members of the public, information is widely available on the effects of the ELF (Economic Limit Factor) in reducing the severance tax, one of the four major sources of state petroleum revenue. In recent years the ELF has functioned to reduce the effective state severance tax rate to approximately one-half of its nominal level. As discussed in Section III.H, the ELF makes severance tax payments more difficult to model.

In sum, implementation of each of these recommendations would help clarify the relationships among the various fiscal mechanisms through which the petroleum net revenue take is divided, Because the pieces of the petroleum puzzle are inter-connected, better information about one aspect will lead to improved understanding of the others.

Appendices

A. *Alaska Benchmarking Study* (Alaska Oil and Gas Association, March 2004)

B. "Details from Study on Alaska Oil Industry are Released" (Alaska State Legislature, News from the House and Senate Majority, c. January 30, 2005)

C. "Wood Mackenzie – Global Oil and Gas Risks and Rewards 2004 Study" (Wood Mackenzie, February 16, 2005)

D. Sourcing and Calculation Notes for Selected Figures

E. Requests for TAPS Tariff Information and Responses from Alaska Department of Revenue

Appendix A.

Alaska Benchmarking Study (Alaska Oil and Gas Association, March 2004)

ALASKA'S GLOBAL RANKING

Alaska Benchmarking Study: Global Oil & Gas Risk & Rewards

	Total Government Take		Weighted Average Total Costs (US$/boe)		Average Post-Take Value (US$/boe)	
1	Cameroon	10.86%	Qatar	1.38	Cameroon	7.83
2	Ireland	19.92%	Iran	1.61	Ireland	5.76
3	Canada (East Coast)	35.17%	Egypt (offshore)	1.73	UK (shelf)	5.50
4	New Zealand	37.51%	Malaysia-Thailand JDA	1.97	Philippines	5.40
5	UK (shelf)	40.77%	Bangladesh	2.31	USA (GoM deep wtr)	5.33
6	Netherlands (offshore)	41.92%	Oman	2.40	Papua New Guinea	5.21
7	USA (GoM deep wtr)	42.10%	Indonesia (offshore)	2.56	Netherlands (offshore)	4.48
8	Italy	42.62%	Australia (offshore)	2.59	Italy	4.43
9	China (offshore)	42.81%	Malaysia	2.73	Denmark	4.35
10	UK (S. Gas Basin)	43.54%	Pakistan	2.77	Congo (Brazzaville)	4.26
11	Pakistan	45.46%	Egypt (onshore)	3.41	UK (S. Gas Basin)	4.12
12	Australia (offshore)	45.51%	Myanmar	3.47	Canada (East Coast)	4.10
13	Philippines	46.12%	India	3.54	China (offshore)	4.04
14	Argentina	46.93%	Venezuela	3.79	New Zealand	3.49
15	Denmark	47.20%	Brunei	3.82	Brazil (shelf)	3.25
16	Brazil (shelf)	47.88%	Algeria	3.93	Yemen	3.21
17	Venezuela	49.56%	Timor Gap	4.01	Australia (offshore)	2.97
18	Congo (Brazzaville)	50.57%	Libya	4.07	Egypt (onshore)	2.87
19	Thailand	50.65%	Bolivia	4.70	Equatorial Guinea	2.75
20	Kazakhstan	51.88%	Nigeria (shelf)	4.72	India	2.74
21	Papua New Guinea	52.27%	Netherlands (onshore)	4.78	Venezuela	2.73
22	Myanmar	54.00%	Argentina	4.79	Myanmar	2.70
23	Cote d'Ivoire	55.34%	Nigeria (deep water)	5.25	Pakistan	2.65
24	Bolivia	55.71%	New Zealand	5.32	Angola (shelf)	2.56
25	Malaysia-Thailand JDA	56.21%	Trinidad & Tobago (offshore)	5.39	Gabon (onshore)	2.54
26	Colombia	57.12%	Philippines	5.46	Tunisia	2.52
27	Ecuador	57.75%	Yemen	5.52	Netherlands (onshore)	2.50
28	Equatorial Guinea	59.69%	Peru	5.67	Gabon (offshore)	2.44
29	Angola (deep water)	59.93%	Indonesia (onshore)	5.72	Thailand	2.36
30	Brazil (deep water)	60.19%	USA (GoM deep water)	5.84	Nigeria (deep water)	2.33
31	Bangladesh	61.18%	Thailand	5.85	Brazil (deep water)	2.27
32	Azerbaijan	61.54%	Brazil (shelf)	5.96	Egypt (offshore)	2.26
33	Netherlands (onshore)	61.67%	Kazakhstan	6.15	Argentina	2.24
34	Tunisia	63.07%	Angola (deep water)	6.22	Cote d'Ivoire	2.23
35	Timor Gap	63.94%	Tunisia	6.27	Ecuador	2.18
36	***USA (Alaska)***	***64.24%***	Netherlands (offshore)	6.28	Colombia	2.12
37	Nigeria (deep water)	64.62%	Sudan	6.41	Angola (deep water)	2.10
38	India	66.82%	Colombia	6.50	Vietnam	2.05
39	Turkmenistan	68.06%	Brazil (deep water)	6.67	Algeria	1.92
40	Vietnam	68.55%	Vietnam	6.73	Sudan	1.90
41	Trinidad & Tobago (offshore)	69.00%	Italy	6.74	Malaysia-Thailand JDA	1.87
42	Indonesia (offshore)	71.01%	Cameroon	6.79	Turkmenistan	1.77
43	Algeria	71.72%	Cote d'Ivoire	6.94	Indonesia (offshore)	1.58
44	Gabon (offshore)	71.81%	Equatorial Guinea	6.96	Kazakhstan	1.55
45	Egypt (offshore)	73.04%	Gabon (onshore)	7.03	Oman	1.54
46	Gabon (onshore)	73.38%	Azerbaijan	7.12	Brunei	1.52
47	Brunei	73.90%	Ireland	7.19	Libya	1.51
48	Angola (shelf)	74.11%	Ecuador	7.43	Azerbaijan	1.49
49	Egypt (onshore)	74.27%	Denmark	7.45	Indonesia (onshore)	1.41
50	Norway	74.74%	UK (S. Gas Basin)	7.51	Norway	1.39
51	Peru	75.04%	Turkmenistan	7.54	Bangladesh	1.37
52	Yemen	75.36%	Gabon (offshore)	7.93	Timor Gap	1.35
53	Sudan	76.96%	Congo (Brazzaville)	8.05	Nigeria (shelf)	1.06
54	Libya	78.73%	China (offshore)	8.21	Malaysia	0.99
55	Qatar	79.09%	Papua New Guinea	8.64	***USA (Alaska)***	***0.90***
56	Indonesia (onshore)	80.13%	Angola (shelf)	8.65	Nigeria (onshore)	0.85
57	Malaysia	81.24%	Norway	8.76	Qatar	0.76
58	Oman	83.19%	UK (shelf)	8.79	Trinidad & Tobago (offshore)	0.69
59	Nigeria (onshore)	87.21%	Canada (East Coast)	10.58	Peru	0.58
60	Nigeria (shelf)	87.44%	***USA (Alaska)***	***12.52***	Bolivia	0.56
61	Iran	93.26%	*Excludes Nigeria (onshore)		Iran	0.20

Source: Wood Mackenzie Study - September 2002 Alaska Oil & Gas Association - March 2004

AOGA

The Alaska Oil and Gas Association is a private non-profit trade association whose 20 member companies represent the majority of oil and gas exploration, production, transportation, refining and marketing activities in Alaska. AOGA's members are:

Agrium Kenai Nitrogen Operations
Alyeska Pipeline Service Company
Anadarko Petroleum Corporation
BP Exploration (Alaska) Inc.
ChevronTexaco Corporation
ConocoPhillips Alaska, Inc.
EnCana Oil & Gas (USA) Inc.
ExxonMobil Production Company
Flint Hills Resources, Alaska
Forest Oil Corporation
Kerr-McGee Corporation
Marathon Oil Company
Petro-Canada (Alaska) Inc.
Petro Star, Inc.
Pioneer Natural Resources Alaska, Inc.
Shell Western E&P Inc.
Tesoro Alaska Company
TOTAL E&P USA, INC.
UNOCAL
XTO Energy, Inc

Alaska Oil & Gas Association
121 W. Fireweed Lane, #207
Anchorage, AK 99503
Phone: (907)272-1481 • Fax: (907)279-8114

Alaska Benchmarking Study

Alaska's Global Ranking

How does Alaska compare with other oil and gas provinces worldwide in terms of government take (taxes & royalties); cost per barrel; and profitability?

To provide a global comparison of relative attractiveness for future E&P investment, the international consulting firm, Wood Mackenzie, completed the Global Oil & Gas Risks & Rewards study in 2002 covering 61 areas within 50 countries including Alaska.

Alaska Has Higher Than Average Total Taxes & Royalties

Alaska ranks 36 out of 61

Total Government Take (federal and state) is calculated to be 64%. State share is approximately 47% and includes royalties, production tax, corporate income tax, property tax and net profit shares. The actual and projected ELF, based on field size, is used in these calculations.

Economic assumptions: Brent marker price = US $19.50 bbl (2002) increasing 2.5% per annum. The median price of ANS West Coast spot was $17.70 from December l990 to February 2003. The State of Alaska Department of Revenue long-term forecast to FY 2015 is $22 per/bbl.

Alaska Has the Highest Total Costs

Alaska ranks 60 out of 60

This ranking is the weighted average of all North Slope fields starting production since 1995. (Earlier studies have confirmed that the per barrel costs for Prudhoe and Kuparuk are among the highest in the world.) Costs include operating, cost of capital, all transportation including pipeline and marine.

* Nigeria (onshore) excluded from this portion of the study.

Alaska Is Challenged in Terms of Profitability

Alaska ranks 55 out of 61

Aggregating the Government Take, which is higher than average, with the weighted average total costs, which are the highest of the 60 worldwide oil and gas provinces studied, the average value of remaining production on the North Slope ranks 55 out of 61.

Appendix B.

"Details from Study on Alaska Oil Industry are Released" (Alaska State Legislature, News from the House and Senate Majority, c. January 30, 2005)

ALASKA STATE LEGISLATURE

News From The House & Senate Majority

web site: http://www.akrepublicans.org
House Majority Press Senate Majority Press
Craig Johnson – (907) 465-5369 Jeff Turner – (907) 465-3803
Renée Limoge – (907) 465-5446

Details from Study on Alaska Oil Industry are Released

(Juneau) – The Legislative Budget & Audit Committee released information from the Wood Mackenzie Global Oil and Gas—Risk and Rewards 2004 today.

The Committee obtained permission to release select information covering exploration and production costs and the State of Alaska's share of oil revenue and profitability. Committee Chair Sen. Gene Therriault (R-North Pole) commented, "This report contains a massive amount of information. Now it's time for us to sit down and try to digest it with the help of additional expertise. We want to make sure we understand what went into the report and why the numbers came out the way they did."

The Committee has retained the State of Alaska's former chief petroleum economist, Chuck Logsdon, to perform a review and evaluation of the study. . . .

Alaska's Costs – Before Government Take

	Capital Costs	Operating Costs	Total Costs
Alaska's Ranking	45/58	56/58	52/58
Alaska's Cost	$3.75	$6.20	$9.94
Global Average Cost	$2.55	$3.34	$5.89

Full Cycle Government Take

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

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

Full Cycle Gov't Take (% Of Pre-Take NPV @10%)

	Low Price ($16)	Base Price ($22)	High Price ($35)
Alaska's Ranking	22/47	16/49	17/53
Take on AK Production	82.17%	72.09%	64.56%
Global Ave. Take	81.05%	74.16%	71.91%

Alaska's Profitability – Full Cycle, Post Government Take

Rate of Return (IRR – Nominal)

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

Net Present Value (NPV @10% in $/Bbl of Oil Equivalent)

	Low Price ($16)	Base Price ($22)	High Price ($35)
Alaska's Ranking	17/58	11/58	8/58
Alaska's NPV	$0.90	$2.14	$4.43
Global Average NPV	$0.65	$1.33	$2.35

Value Creation Ratio

	Low Price ($16)	Base Price ($22)	High Price ($35)
Alaska's Ranking	22/66	22/66	19/66
Alaska's VCR	1.98	3.33	5.82
Global Ave. VCR	1.90	2.84	4.26

Appendix C.

"Wood Mackenzie – Global Oil and Gas Risks and Rewards 2004 Study"
(Wood Mackenzie, February 16, 2005)

Wood Mackenzie's Global Oil and Gas Risks and Rewards Study 2004

FOR IMMEDIATE RELEASE

Edinburgh, 16 February 2005 - A recently published report entitled *Global Oil and Gas Risks and Rewards (GOGRR)* by leading global research and consulting company, Wood Mackenzie, compares exploration performance and returns for International Oil Companies (IOCs) in 66 areas across 58 countries between 1994 and 2003. Using Wood Mackenzie proprietary data and commercial models specific to given fields and areas, this independent study assesses exploration performance over the last 10 years.

This new study enhances a similar study conducted by Wood Mackenzie in 2002 but, while some aspects are comparable, others are very different. The new study focuses on exploration activity and discoveries made during the period 1994 to 2003, while the previous study covered 1991 to 2000.

The new study includes an analysis of the economics of discoveries made during the study period but on the basis of client feedback does not repeat an assessment of the economics of remaining production from older fields that were a feature of the 2002 study. As a result, a direct comparison of some of the study results is not possible.

For Alaska, the 2004 study highlights these key points:

Field Costs: Alaska has relatively high field costs (capital and operating) ranking 52^{nd} of the 58 areas that made discoveries between 1994 and 2003, with a weighted average total unit field costs of US$9.95/boe. This compares to the GOGRR 2002 results for fields developed in 1995 or later, where Alaska ranked last of 60.

Exploration Activity: Alaska ranks in the top quartile in terms of average oil discovery size (99 mmboe) and in the top half in terms of commercial success rate (18%) and reserves discovered (918 mmboe) during the study period 1994-2003. These results and Alaska's ranking position are comparable to the GOGRR 2002 results.

Government Take: Government Take – in both GOGRR 2002 and 2004 – is calculated as between 55% and 72% of the Pre-Take Net Present Value using a 10% discount rate (NPV10), depending on the basis used (i.e. Development or Full Cycle, Field Life or Remaining) and generally ranks in the top half from a company perspective. GOGRR 2004's price sensitivity analysis shows that the Alaskan Government Take decreases (in percentage terms) as prices increase.

Value per barrel: Alaska ranks in the top quartile in terms of post-take development and Full Cycle NPV10 per boe (US$2.14/boe under the base price) and in the top third in terms of absolute Full Cycle value created (US$1.97 billion under the base price). These values are not directly comparable with the value of all remaining production reported in the GOGRR 2002 study. The 2002 study results were dominated by Prudhoe Bay and other older fields, with much longer production profiles (particularly in Prudhoe Bay's case as a result of the substantial gas reserves that are yet to be developed).

Editor's notes:
Wood Mackenzie is the premier provider of global energy and life sciences information, advisory services and knowledge-based consulting. Wood Mackenzie traces its origins back to 1844 as an Edinburgh-based firm that served clients with a focus on superior advice and service. Building upon that foundation of knowledge, Wood Mackenzie has provided research and advice to the life sciences, energy and financial services industries since 1973.

Further information:
A document including full detail of the comparison between the two studies is available from kirsten.oosterhof@woodmac.com.

For further information, or an interview with David Barrowman, VP Energy Consulting or Graham Kellas, VP Petroleum Economics, for Wood Mackenzie, please contact:

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Wood Mackenzie – Global Oil and Gas Risks and Rewards 2004 Study

Methodologies
Wood Mackenzie employed distinct methodologies on our 2002 and 2004 *Global Oil and Gas Risks and Rewards* (GOGRR) studies. Client feedback from GOGRR 2002 suggested that the most useful aspects of the study were those related to recent investment – in exploration and new field developments – and the economics of remaining production from older fields was of limited usefulness. Clients requested more investigation of the attractiveness of exploration investment in the new study, instead of repeating the analysis of older fields' remaining economics. In response, Wood Mackenzie altered the methodology of the GOGRR 2004 study updating only the parameters associated with exploration and new field development. As such, not all of the results – for example Expected Monetary Value (EMV) - from the two reports are directly comparable. The main changes in methodology between the two studies are:

Treatment of Existing Production: The 2004 study only includes the economics of exploration activity and new discoveries made between 1994 and 2003 while the 2002 study includes the economics of remaining production from all fields

Time Period: The 2004 study covers the period from 1994 to 2003 while the 2002 study covered the 1991 to 2000 period in the EMV analysis.

Field Coverage: The 2004 study includes 12 discoveries made in the period 19942003, of which Alpine was the most significant. The 2002 study's values were based on the remaining production profiles of all known fields at that time.

GOGRR 2002 (February 2002) Methodology
The GOGRR 2002 study had two distinct parts:

Expected Monetary Value (EMV)
This considered exploration success rates and reserves discovered between 1991 and 2000. The average Net Present Value (NPV) of a sample of hypothetical field development economics (based on the discoveries made in the study period) were calculated and then risked according to the success rate. This risked value was then compared with the risked average cost of drilling an exploration well to calculate the EMV.

Remaining Value of Existing Developments
This calculated the value (pre and post-take) of remaining production in all fields, including old fields (e.g. Prudhoe Bay in Alaska) under a single oil price scenario ($19.50/bbl in 2002, increasing at 2.5% per annum thereafter). Countries were ranked on the basis of remaining reserves, weighted average pre-take and post-take values (NPV @ 10%) and Government Take. The results in each country are largely driven by the revenue, operating costs and fiscal terms associated with the largest producing fields, as they are weighted by remaining reserves.

Additional rankings based on the development and operating costs ($/boe) for fields developed after 1995 and values were included. Comparative costs for older fields are not meaningful because of inflation factors.

GOGRR 2004 (November 2004) Methodology

GOGRR 2004 has a single focus, based on the exploration activity and discoveries made between 1994 and 2003. GOGRR 2004 rankings include success rates and reserves discovered, comparable to GOGRR 2002. Field economics in GOGRR 2004 (NPV, Internal Rate of Return (IRR), Government Take) are based on the full field life rather than the remaining values that were reported in GOGRR 2002. In addition, the cost of all E&A wells drilled during the period were estimated and the total drilling cost in each area is then compared with the total value of developed discoveries to generate the Full Cycle value of exploration over the period. Countries are then also ranked according to Full Cycle economics (NPV, IRR, Government Take). This analysis was not included in GOGRR 2002. Moreover, there is no consideration in the GOGRR 2004 report of the value of any discoveries made prior to 1994.

GOGRR 2004 models the discoveries as they have been developed – thus, some fields have historical (i.e. pre-2004) cash flows as well as future “remaining” cash flows. Historical cashflows are compounded to 1 Jan 2004 and future cashflows are discounted to the same date, to generate the total value for each discovery. GOGRR 2004 also includes price sensitivity analysis, assuming the following oil prices in 2007 (each escalating at 2.5% p.a. thereafter): US$16/bbl (Low); US$22/bbl (Base); US$35/bbl (High) Thus, compared to GOGRR 2002, there is a significant increase in the base price between 2002 and 2007, which will impact the value of discoveries onstream during this period.

Exploration Activity

	GOGRR 2004	GOGRR 2002	Comments
No. Exploration Wells	68	50	Cook Inlet exploration activity (and discoveries) were not included in GOGRR 2002, but are included in GOGRR 2004.
No. Oil Discoveries	9	13	
No. Gas Discoveries	3	0	
Commercial Success Rate	17.6%	26.0%	
CSR Ranking Position	23 / 66	9 / 61	
Commercial Reserves Discovered (mmboe)	918	1,285	
Reserves Ranking Position	26 / 66	25 / 61	
Average Commercial Oil Discovery Size (mmboe)	99	99	
Reserves Ranking Position	13 / 66	16 / 61	

Field Development and Operating Costs

	GOGRR 2004 (1994-2003 discoveries)	GOGRR 2002 (Developments: 1995 onwards)	Comments
Fields modelled	Alpine Aurora Eider Happy Valley Lone Creek Meltwater Midnight Sun Nanuq Orion Palm Sourdough Wolf Lake	**Discovery date** ***Pre-1991*** Badami Liberty Northstar Point Thomson Tabasco West Sak ***1991-1993*** Fiord Polaris Tarn ***1994-2000*** Alpine Aurora Eider Meltwater Midnight Sun Nanuq Palm Sourdough	In GOGRR 2002: ❑ only the weighted average costs of developments from 1995 onwards were included, ❑ when calculating the remaining value of Alaska, all fields producing at the time were included. The older Alaskan fields which are included in the values – but not in the costs comparison - are: Endicott Kuparuk Lisburne Milne Point Niakuk Point McIntyre Prudhoe Bay Sag Delta North
Weighted Average Capex ($/boe)	3.75	3.23	GOGRR 2004 costs in 2004 terms; GOGRR 2002 costs in 2002 terms
Weighted Average Opex ($/boe)	6.20	9.28	Tanker tariffs to the West Coast were removed in GOGRR 2004 for consistency with all other areas as FOB point of export. Alaska differs from other areas because it "exports" to the same country.
Weighted Average Field Costs ($/boe)	9.94	12.52	
Costs Ranking Position	52 / 58 *	60 / 60 *	

** 8/66 GOGRR 2004 areas had no discoveries; 1/61 GOGRR 2002 areas had no 1995+ developments*

Weighted Average Values

	GOGRR 2004 (1994-2003 Full Cycle Values)	**GOGRR 2004** (1994-2003 Field Development Values)	**GOGRR 2002** (1995+ Fields)	**GOGRR 2002** (All Fields)	**Comments**
Weighted Average **Remaining** Pre-Take NPV @ 10% US$/boe Base Price	n/a	n/a	3.94	2.52	GOGRR 2002 considers the remaining value of production in all fields – the revenue and operating costs of the largest producing fields therefore dominate the results. GOGRR 2002 All Fields' remaining value is dominated by Prudhoe Bay economics (including gas) as these provide the most reserves in the weighted average calculation.
Weighted Average **Field Life** Pre-Take NPV @ 10% US$/boe Base Price	7.68	8.54	n/a	n/a	GOGRR 2004 considers the full field life values of discoveries made between 1994 and 2003 In addition, prices in GOGRR 2004 are higher than in GOGRR 2002, notably between 2002 and 2007.
Pre-Take Ranking Position	16 / 58 *	22 / 58 *	46 / 60 *	58 / 61	
Government Take (% Pre-Take NPV@10%) Base Price	72.1%	64.1%	55.2%	64.2%	Weighted average Govt. Take differences reflect: ❑ different fields, ❑ different prices, ❑ different bases (field life vs remaining values)
Government Take Ranking Position	16 / 58 *	21 / 58 *	24 / 60 *	36 / 61	
Weighted Average **Remaining** Post-Take NPV @ 10% US$/boe Base Price	n/a	n/a	1.76	0.90	
Weighted Average **Field Life** Post-Take NPV @ 10% US$/boe Base Price	2.14	3.06	n/a	n/a	
Post-Take Ranking Position	11 / 58 *	14 / 58 *	41 / 60 *	55 / 61	

** 8/66 GOGRR 2004 areas had no discoveries; 1/61 GOGRR 2002 areas had no 1995+ developments*

Appendix D.

Sourcing and Calculation Notes for Selected Figures

Appendix D. Notes on Sources and Calculations for Figures III.-2, III.-4, III.-6, III.-8, III.-9 and III.-13: Overview

One of the goals of this report is to make information on North Slope production associated Alaska pipeline operations transparent and accessible. To this end, the analysis in Section III starts with information from the Alaska Department of Revenue (ADOR) semi-annual *Revenue Sources Book* (identified in this appendix as *RSB*) and relies on that document insofar as possible. However, some data critical to this analysis cannot be ascertained through *RSB*. When other information sources are used, they are noted below and the method of employment is shown, as necessary. To facilitate access, when the source data are from ADOR, an identifying document name is provided; when data must be obtained elsewhere, that source is given.

Conversion from fiscal year to calendar year requires adjustments to recognize the conventions ADOR uses to track petroleum receipts for state budget and accounting uses. Royalties and severance taxes, which typically provide more than three-quarters of state petroleum receipts, are paid monthly. Because the state fiscal year begins July 1 of the preceding calendar year (*i.e.*, fiscal year 2005 began July 1, 2004), ADOR fiscal year summaries count petroleum receipts for June through December of the prior calendar year and January through May of the current calendar year. When readily available from ADOR, monthly data were used to convert to calendar year display. In some cases, however, the requisite calendar year data were not readily available through ADOR. In these cases, to fiscal year data were converted to calendar year using the following formula:

CY = (5*[current FY] + 7*[next FY]) / 12.

When this convention has been employed to convert from fiscal year to calendar year basis, it will be noted below.

Appendix D. Notes on Sources and Calculations, Figure III.- 2:

Line Source or Calculating Note

(1) CY average Alaska North Slope crude oil market price from ADOR data. (RSB or "Oil Price Archives," at http://www.tax.state.ak.us/programs/oil/prices/index.asp).

(2) 1988-2000 – estimated from ADOR fiscal year data; 2001 – 2004 – from ADOR "Shortcut" monthly totals.

(3) Line (1) * Line (2).

4) a. Derived from *RSB*, various dates (no changes necessary; property tax typically assessed and collected during the first half of the calendar year).
b. 1988 – 2004 – *RSB*, Spring 2005, p. 92 (converted from CY data); 2005 – *RSB*, Spring 2005, pp. 21 and 92.
c. No revision necessary (ADOR data derived from TAPS tariffs, which are filed on a CY basis).

(5) Space reserved for calculating results of operating common carrier feeder pipelines from remote North Slope fields (Kuparuk, Milne Pt., Alpine, Northstar, Badami and Endicott) to TAPS (Pump Station #1).

(6) See Fig. III.-4 for additional TAPS tariff estimating detail.
a. Space reserved (not estimated in ADOR revenue share analysis).
b. ADOR (Fig. III.-1); derived from TAPS tariffs (ADOR estimates TAPS = 20% of total oil and gas property tax; see Line [4a]); no revision necessary for CY entry [TAPS tariffs are filed on a CY basis]).
c. ADOR (Fig. III.-1); derived from TAPS tariffs (ADOR estimates SIT = 20% of total tariff income tax allowance; see Line [4c]; no revision necessary for CY entry (see Line [6b]).
d. ADOR (Fig. III.-1); derived from TAPS tariffs (ADOR estimates FIT = 80% of total tariff income tax allowance; see Line [4c]; no revision necessary for CY entry (see Line [6b]).
e. ADOR (Fig. III.-1); includes per-barrel allowance and return on new capital investment; no revision necessary for CY entry (see Line [6b]).
f. ADOR (Fig. III.-1); includes per-barrel allowance and return on new capital investment; no revision necessary for CY entry (see Line [6b]).
g. Space reserved (not estimated in ADOR revenue share analysis).

(7) a. Line (6b) + Line (6c).
b. Line (6d)
c. Lines (6e + 6f + 6g).

(8) Space reserved (not estimated in ADOR revenue share analysis).

(9) Calculated by ADOR as Line (2) * Line (9a).

(9a) ADOR estimate: Line (2) – Line [10a].

(Continued on next page.)

Appendix D. Notes on Sources and Calculations, Figure III.- 2 (cont.):

Line Source or Calculating Note

(10) Calculated by ADOR as Line (2) * Line (10a).

(11) a. 1988-2003 – Converted from fiscal year data in ADOR share analysis; 2004 from ADOR “PETREV” monthly totals (incl. bonus payments, etc.).
b. 1988-2003 – Converted from fiscal year data in ADOR share analysis, less Line [11c] ; 2004 from ADOR “PETREV” monthly totals (incl. settlements, etc.), less Line [11c].
c. From ADOR “PETREV” monthly data.
d. Derived from *RSB*, various dates ADOR estimates North Slope property tax = 80% of total oil and gas property tax; see Lines [4a], [6b]); no revision necessary for CY entry [TAPS tariffs are filed on a CY basis]).
e. Cook Inlet royalty and severance estimated from ADOR “PETREV” monthly data and removed from Line [11]; replaces Cook Inlet entry in Figure III.-1, Note 1.

(12) Line (2) * Line (12a).
a. ADOR data entry – lifting + capital (depreciation, depletion and amortization) costs (1993-1996 and 1999-2003 are calendar year figures).

(13) a. Total state petroleum corp. income tax (Line [4b]) less (Line [6c]).
b. ADOR calculates as 35% of wellhead revenue (Line [10]) less production costs (Line [12]), including state and local taxes and royalty (Line [11]).
c. Industry production profit = wellhead revenue (Line [10]) less production costs (Line [12]), including state and local taxes and royalty (Line [11]) and income taxes (Lines [13a and 13b]).

(14) Sum of Lines (14a + 14b + 14c).
a. Line (7a) + Line (13a).
b. Line (7b) + Line (13b).
c. Line (7c) + Line (13c).

Appendix D. Notes on Sources and Calculations, Figure III.- 4:

Line Source or Calculating Note

(1) 1999: Estimated from ADOR data (FY 1999 = $2.70 [Spring 2000 *RSB*, p. 22]; FY 2000 = $2.74 [Spring 2001 *RSB*, p. 22]).
2000: Estimated from ADOR data (FY 2000 = $2.74 [Spring 2001 *RSB*, p. 22]; June – Dec. = $2.91 [“Shortcut” Avg.]).
2001 - 2003: ADOR "Shortcut" monthly average.
2004: From filed tariffs (Anadarko Petroleum Co. tariff protest, Dec. 16, 2004).

(2) 1999 – 2000: estimated from ADOR fiscal year data;
2001 – 2004: From ADOR “Shortcut” monthly totals.

(3) Calculated as Line (10) – (Lines [3] thru [9]).
(Note: To determine the TAPS Total Revenue Requirement, Line [10] would be the sum of Lines [2] thru [9]).

(3a) 1999 – 2000: TAPS property tax (part of the operating requirement under TSM) estimated at 20% of total annual oil and gas property tax payments, as reported by ADOR.
2001 – 2004: TAPS property tax (part of the operating requirement under TSM) estimated at 2.0% of total assessed valuation, as reported by ADOR.

(4) 1999 – 2002: "TSM (TAPS Settlement Methodology) Line-by-Line Calculation." (received from ADOR, March 2001).
2003 – 2004: Estimated (straight-line projection from 2002)

(5) 1999 – 2000: "TSM (TAPS Settlement Methodology) Line-by-Line Calculation." (received from ADOR, March 2001).
2001 – 2004: ADOR (estimated from TAPS tariff data)

(6) 1999: (a) and (b): "TSM (TAPS Settlement Methodology) Line-by-Line Calculation."
2000 – 2002: (a) PBA (calculated from tariff data) * Line (10); (b) "TSM (TAPS Settlement Methodology) Line-by-Line Calculation."
20003 – 2004: (a) PBA (calculated from tariff data) * Line (2); (b) estimated (prior year * 1.1)

(7) 1999 – 2002: "TSM (TAPS Settlement Methodology) Line-by-Line Calculation." (received from ADOR, March 2001).
2003 – 2004: Estimated (straight-line projection from 2002).

(8) TAPS Settlement Agreement (1985), Exhibit E.

(9) 1999 – 2004: Adjustments from prior years and non-transportation revenues (included in Line [1], above) cannot be calculated from available data.

(10) 1999 – 2004: Calculated as Line (1) * Line (2). (See note at Line [3].)

Appendix D. Notes on Sources and Calculations, Figure III.- 6:

Line Source or Calculating Note

(1) From ADOR averages ("Shortcut" and *RSB*).

(2) 1999: ADOR worksheet (FY 99 = 0.10; FY 00 = 0.11).
2000: Estimated from ADOR data ("Shortcut" June-Dec. avg.).
2001 –2003: ADOR "Shortcut" monthly average.
2004: Estimated from ADOR data ("Shortcut" Jan.-May avg.)
2005: Estimated: CY 04 + $0.05/bbl.

(3) 1999: Est. from ADOR worksheet (FY 1999 = $1.47; FY 2000 = $1.76).
2000: Est. from ADOR data. ("Shortcut" June-Dec. avg.).
2001 – 2003: ADOR “Shortcut” monthly average.
2004: Est. from ADOR *”Shortcut,” Jan.-May avg., and Fall 2004 *RSB.*

(4) Sum of lines (1) through (3).

(5) The quality bank differential is one of two price adjustment entries in ADOR's "Other Deductions and Adjustments" (*RSB*, Fall 2004, p. 31). The quality bank differential adjustment represents the contribution of each input to TAPS to the change in value of the blended stream. These transactions appear to be intra-company payments that should not alter the market price of ANS crude, which represents the value of the delivered blended stream. Estimating bases are provided here to facilitate reconciliation with other ADOR data in this column, such as Feeder Pipeline tariffs.
1999: Est. from ADOR worksheet (FY 1999 = $0.00; FY 2000 = $0.01)
2000: Est. from ADOR worksheet (FY 2000 = $0.01; FY 2001 = [$0.19])
2001: Est. from ADOR worksheet (FY 2000 = [$0.19]; FY 2001 = [$0.19])
2002: Est. from ADOR worksheet (FY 2002 = [$0.19]; FY 2003 = [$0.13])
2003: Est. from ADOR worksheet (FY 2003 = [$0.13]; FY 2003 = [$0.23])
2004 – 2005: Not estimated

(6) The ADOR entry, "Wellhead to Market Differential" (also included in Other Deductions & Adjustments) is an artificial or forcing number that reconciles the difference between the average wellhead price, as reported by taxpayer, and the implied wellhead price necessary to produce actual receipts. (Considerations unique to each taxpayer result in total payments different from the average.) Estimating bases are provided here to facilitate reconciliation with other Alaska Dept. of Revenue data in this column, such as feeder pipeline tariffs.
1999: Est. from ADOR worksheet (FY 1999 = [$0.06]; FY 2000 = [$0.57]).
2000: Est. from ADOR worksheet (FY 2000 = [$0.57]; FY 2001 = $0.42).
2001: Est. from ADOR worksheet (FY 2001= $0.42]; FY 2002 = [$0.10]).
2002: Est. from ADOR worksheet (FY 2002 = [$0]; FY 2003 = [$0.])
2003: Est. from ADOR worksheet (FY 2003 = [0.26]; FY 2004 = [$0.18])
2004 - 2005: Not estimated

Appendix D. Notes on Sources and Calculations, Figure III.- 8:

Line Source or Calculating Note

(1) 2000 from *ConocoPhillips 2002 Annual Report*, p.99; 2001-2003 from *ConocoPhillips 2003 Annual Report*, p. 102 (Crude Oil + NGLs)

Costs allocated by converting Cook Inlet natural gas to barrels of oil equivalent (boe), then allocating costs on a boe basis and removing Cook Inlet portion of boe costs on following basis (from ConocoPhillips annual report data):

2000 – ANS Oil + NGLs = (207,000+19,000)*365/100,000; CI Nat. Gas = 158,000,000*365*180/1,000,000/1,000,000.

2001 – ANS Oil + NGLs = (339,000+25,000)*365/100,000; CI Nat. Gas = 177,000,000*365*180/1,000,000/1,000,000.

2002 – ANS Oil + NGLs = (331,000+25,000)*365/100,000; CI Nat. Gas = 175,000,000*365*180/1,000,000/1,000,000.

2003 – ANS Oil + NGLs = (325,000+23,000)*365/100,000; CI Nat. Gas = 184,000,000*365*180/1,000,000/1,000,000.

(2) Net ANS production grossed up for royalties ([line 1] / [1-0.125]).

(3) 2000 from *ConocoPhillips 2002 Annual Report*, p.98; 2001-2003 from *ConocoPhillips 2003 Annual Report*, p. 101 (figures include Crude Oil, NGLs + Cook Inlet gas).

(4) ANS costs estimated by converting Cook Inlet natural gas to barrels of oil equivalent (boe), then allocating costs on a boe basis and subtracting Cook Inlet portion of boe costs from Line (3).

(5) Based on ADOR forecast royalty receipts 2005 through 2015, CI = 5% of total Alaska O&G production value. Then, using ADOR ration of
TAPS property tax to production of 4:1, CI = 4.04% of total O&G production tax (CI = 5, ANS = 95 and TAPS = 23.75 [95 x .2]; 5 / 123.75 = 4.04%). ConocoPhillips ANS property tax assumed to be 39.4% of ANS total (ADOR factor).

(6) For 2000, 0.22600 bpd = 236.65 days at July 1 avg. .34857 bpd.

(7) ADOR estimated lifting costs per barrel of oil x barrels of oil produced during calendar year.

(8) Line (4) less (line [5] + line [6] + line [7]). (This item is added to DD&A totals, per note in statistics section of ConocoPhillips annual report.)

(9) 2000 from *ConocoPhillips 2002 Annual Report*, p.98; 2001-2003 from *ConocoPhillips 2003 Annual Report*, p. 101 (figures include Crude Oil, NGLs + Cook Inlet gas).

(10) ANS costs estimated by converting Cook Inlet natural gas to barrels of oil equivalent (boe), then allocating costs on a boe basis and subtracting Cook Inlet portion of boe costs from Line (3).

(11) Estimated per-barrel lifting costs through 2002 from ADOR worksheet (2003 increased by average increase in the three prior years).

(12) Line (10) / Line (2).

(13) Line (8) / Line (2)

(14) Line (12) + Line (13).

(15) Line (11) + Line (14).

(16) ADOR revised 1998 estimate of $4.24 per barrel increased annually by $0.235 per barrel to reach $5.41 in 2003; see discussion in text.

<u>Appendix D. Notes on Sources and Calculations, Figure III.- 9:</u>

<u>This worksheet makes changes to Figure III.- 2 at the following lines:</u>

Line   Source or Calculating Note

Line	Source or Calculating Note
(5)	1988 – 1990: Calculated at 1991 estimate ($0.10/bbl. weighted average). 1991 – 1992: From: R.A. Fineberg, *North Slope Profits and Production Prospects* (report to the Alaska State Legislature, 1992), pp. 43-49, 60-66. 1993 – 1998: From: R.A. Fineberg, *How Much Is Enough? Estimated Industry Profits from Alaska North Slope Production and Associated Pipeline Operations, 1993 – 1998* (Oilwatch Alaska, 1998). 1999 – 2004: Estimated from ADOR data (see Figure III.-6, notes to Line [2]).
(5c)	Estimated at 15.0% of Line (5).
(6)	1988 – 1998: From aggregate TAPS tariff data (provided by ADOR, March 2001).
(6a)	Includes depreciation; estimated from 1999 calculated as Line (6) minus the sum of Lines (6b) thru (6g).
(6b)	Estimates from 1999 recalculated per Figure III.-4, Line (3a).
(6c)	Estimates from 1999 recalculated per Figure III.-4, Line (5).
(6d)	Estimates from 1999 recalculated per Figure III.-4, Line (5).
(6e)	Includes per-barrel allowance and return on new capital investment; estimates from 1999 recalculated per Figure III.-4, Line (6).
(6f)	No revisions.
(6g)	1988 – 2004 from TAPS Settlement Agreement, 1985, Exhibit E.
(8)	1988 – 1990: Line (9) minus (Line [5] + Line [6]). 1991 – 1992: From *North Slope Profits and Production Prospects*, pp. 23, 40. 1993 – 1998: From *How Much is Enough?*, pp. 28, 37-40 and 42. 1999 – 2004: Estimated from ADOR data (see Figure III.- 6, Line (3).
(9)	1988 – 1999: calculated as Line (2) * Line (9a). 1991 – 2004: Sum of Lines (5) + (6) + (7).
(9a)	1988 – 1990: Derived from wellhead price. 1991 – 2004: Line (9) / Line (2).
(12a)	1999 – 2004: Revised per Figure III.- 8, Line (16).
(13a)	1999 – 2004: Revised per Figure III.-4, Line (5).

Appendix D. Notes on Sources and Calculations, Figure III.- 13:

This worksheet makes changes to Figure III.- 9 at the following lines:

Line   Source or Calculating Note

(13b)   1996 – 2004: Revised per Figure III.- 12.

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Appendix E.

Requests for TAPS Tariff Information and Responses from Alaska Department of Revenue.

The TAPS owners file separate tariffs (shipping charges) annually. Between 1985 and 2002, the basis for TAPS tariffs was a 1985 settlement agreement between the TAPS owners and the state of Alaska. That agreement established a complex formula for determining the annual total tariff requirement, which became the accepted ceiling level for annual tariff filings. As recently as December 2001, the Alaska Department of Revenue provided interested citizens a complete copy of the 176-line worksheet that provided the details of the TAPS owners' actual tariff filings on a weighted average basis, as well as the calculations for each year since TAPS entered operation in 1977.[109] Because that worksheet combined the filings of each individual TAPS owner, weighted for its percentage of throughput, no individual company's actual filings were revealed.

Similar information was requested for this report in December 2004. At that time, the Revenue Department responded that the information would be forthcoming.[110] Subsequently, however, department personnel advised the author that the Alaska Department of Law, which manages TAPS tariff issues, now considered that information confidential.[111] After several other attempts to locate the requisite information failed, on March 15, 2005, the author addressed a scaled down request to ADOR, requesting: (1) the weighted average TAPS tariffs for CY 2001 through CY 2005 filed at RCA or FERC; and (2) the amounts in each of the following TSM element lines:

a. Operating and capital costs
b. State and local property tax (TAPS)
c. State income tax (TAPS)
d. Federal income tax (TAPS)
e. After-tax margin
f. Recovery of deferred return
g. DR&R.[112]

After follow-up phone calls and discussion with Alaska Department of Law attorneys, the following response to that request was received April 7, 2005:

[109] E-mail from Dan Dickinson, Director, Alaska Department of Revenue Tax Division, to the author, in response to a request for confirmation that the tariff worksheet the department had provided in March 2001 was indeed public information, Nov. 5, 2001.

[110] E-mail from Dan Dickinson, Director, Alaska Department of Revenue Tax Division, to the author, Dec. 2, 2004.

[111] Jon Larson, Tax Division economist, December 2005 (personal communication).

[112] E-mail request to Randy Hoffbeck, Tax Division, Alaska Department of Revenue, Mar. 15, 2005.

STATE OF ALASKA

DEPARTMENT OF REVENUE

Tax Division

FRANK MURKOWSKI, GOVERNOR

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April 7, 2005

Mr. Richard A. Fineberg
P.O. Box 416
Ester, Alaska 99725

Re: March 15, 2005, Public Records Request

Mr. Fineberg:

I am responding to your March 15, 2005, letter to Randall Hoffbeck, in the Department of Revenue's Tax Division, requesting certain Trans-Alaska Pipeline System (TAPS) tariff information. I am treating your letter as a request under the Alaska Public Records Act (AS 40.25.100—40.25.220). Mr. Hoffbeck previously extended the 10-working-day response time set out in 6 AAC 96.325(a) by an additional ten days, as provided for under subsection (d) of that section. The deadline for this response is April 12, 2005.

The only documents this Department has that might be responsive to your request are documents developed by the Department of Law's consulting expert Dr. Tom Horst. These documents are not disclosable because they are attorney work product, which is confidential under state and federal law. AS 40.25.120(a)(4); 6 AAC 96.335(a)(4); *see also, Hickman v. Taylor*, 329 U.S. 495 (1947). These documents were prepared under the direction of the Department of Law and for its use in analyzing TAPS issues in the course of deciding whether to initiate litigation and in advising agencies affected by the TAPS tariffs. On some occasions, this Department has received copies of certain of these documents in the course of the Department of Law rendering legal advice to State agencies with respect to TAPS tariffs. The documents transferred to this Department remain protected under the work product doctrine.

The analyses performed for the years 2003, 2004 and 2005 have an additional layer of protection. The TAPS Settlement Agreement (TSM), approved by the FERC, requires the State to keep the information filed by TAPS Carriers confidential for a period of three years from the filing date. The work product created by Dr. Horst is based on that confidential information and disclosure of his work could compromise the confidentiality of the underlying data.

Under the TSM, the confidentiality of individual company information is lifted after three years from the filing date. Thus, the individual Carrier information that was used by Dr. Horst to create the documents for the calendar years 2001 and 2002 is no longer confidential. If you would like those documents, please contact Assistant Attorney General Jan Levy at the Department of Law. We do not have those documents in the Department of Revenue. You may contact Jan at 465-4135 to request that information. These documents would allow you to perform your own analysis for the years 2001 and 2002.

Sincerely,

William A. Corbus

William A. Corbus
Commissioner

Cc: Jan Levy, Assistant Attorney General