Expert Report

Of

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3AN-06-8446 CI (07-09)
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I. INTRODUCTION AND SUMMARY

1. I am Charles J. Cicchetti, Ph.D. I am an economist who specializes in the fields of energy and environmental economics and finance. I have a B.A. from The Colorado College and a Ph.D. from Rutgers University. I also did post-doctoral work at Resources for the Future, where I authored a book entitled Alaskan Oil: Alternate Routes and Markets[1] in 1972.

2. I was a tenured Full Professor of Economics and Environmental Studies at the University of Wisconsin, Madison; served as Deputy Director of the Energy and Environmental Policy Center at Harvard University; and until recently, held the Jeffrey and Paula Miller Chair in Government, Business, and the Economy at the University of Southern California. My full résumé is attached as Appendix A.

3. The purpose of this Report is to explain, based upon my forty years of involvement in Alaska oil matters and my economic expertise, why I conclude that the economic value of the Trans Alaskan Pipeline System (TAPS) and Alaska's northern petroleum production and deposits are inextricably tied to each other. Indeed, the value of the crude oil is the economic driver for the valuation of TAPS, and *vice versa*. It is not an overstatement to conclude that neither would be worth much without the other. TAPS was built for the express and exclusive purpose of moving oil from the North Slope to Valdez, not to earn or collect tariff income. TAPS is an integrated component of the TAPS Owners' Alaskan oil upstream and downstream related business, investments, and activities. These Owners would not and did not independently finance the original construction of TAPS without the backing of their parent corporations. The investment

[1] Baltimore, Maryland: The Johns Hopkins University Press, 1972.

in TAPS was not made to earn regulated tariff income, as the current president of BP Pipelines (Alaska) Inc., Mr. Charles Coulson confirmed in his recent deposition.[2] The exchange is illuminating:

> "Q. On the North Slope, pipelines are not built for regulatory return alone, are they?
>
> THE WITNESS: They're built to provide access to markets."

Mr. Coulson also confirmed that basin opening producers typically require the producer to make the infrastructure development investment and that no non-producer has developed a pipeline in Alaska.[3] I explain below that the Owners used the resource value to justify and finance what was then the largest privately financed project in human history. Mr. Coulson also agreed that the purpose of TAPS was to "monetize" the value of the petroleum resources.[4] The interdependence between the economic value of TAPS and northern petroleum resources are tied to each other just as any notion of their future economic obsolescence would be.

4. I will also explain why the TAPS Owners' proposed tariff income method for evaluating the pipeline and transportation investments at Valdez is flawed as a regulatory matter and does not reasonably capture all the economic and financial benefits related to TAPS ownership. The reasons for rejecting such an erroneous view are many. Yet, one may suffice. The logical conclusion is that in a world with no tariff income, under a tariff income approach TAPS would have no value. Since it is the only facility that can move the current production on the North Slope of more than 600,000 barrels of oil per day, it

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[2] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc., et al. vs. State of Alaska et al, Case No. 3AN-06-8446 CI (consolidated); December 8, 2010; page 59.

[3] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc., et al. vs. State of Alaska et al, Case No. 3AN-06-8446 CI (consolidated); December 8, 2010; pages 57 and 58.

[4] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc., et al. vs. State of Alaska et al, Case No. 3AN-06-8446 CI (consolidated); December 8, 2010; page 58.

would be preposterous and rather silly to assign a zero economic value to an asset that is owned primarily by the producers of these many barrels of oil.

5. This is rather like a person who owns an apartment building that has been fully paid for deciding to let his children live rent-free. Other than taxes and operating expenses, this is all an intra-family transfer of value with no cash exchanged other than taxes and incidentals. This is very similar to the "pocket to pocket" no money transfer that Mr. Coulson used to explain how TAPS functions.[5] The economic power of TAPS and its continuing economic life are derived from the market value of crude oil. Despite forecast throughput declines, the increasing price of crude oil forestalls the economic obsolescence of TAPS. In 2010, TAPS transported about 619 thousand barrels per day according to the Alyeska website.[6] Even if this declined to 100,000 barrels per day or less, with oil prices rising to about $100 per barrel in early 2011 outside the U.S.,[7] the pre-transportation value of the crude would be $10,000,000 per day, or about $3.65 billion per year. At today's current and forecasted crude prices, the TAPS tariff is not a major determinant of producers' income or the value of their North Slope reserves.

6. I explain below why prices of crude could easily be greater than $100 per barrel and that there is little risk the Owners would abandon these valuable upstream reserves that are likely to increase significantly in value. Future prices of crude are a very important determinant of the economic value and life of the reserves, which in turn determines the economic value of TAPS, the only viable means of extracting these reserves. Future

[5] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc., et al. vs. State of Alaska et al, Case No. 3AN-06-8446 CI (consolidated); December 8, 2010; pages 55 and 194.

[6] Alyeska Pipeline, "Pipeline Facts." http:www.alyeska-pipe.com/Pipelinefacts/Throughput/html.

[7] On January 28, 2011, the Financial Times reported that crude oil hit $99.63 per barrel for the ICE March Brent. The Financial Times also explained that the anomaly for the all-time high $12 gap between Brent and WTI prices was due to exceptional inventories at Cushing, Oklahoma. See Javier Blas and Richard Edgar, "Oil Near $100 as Mideast Tensions Grow." Financial Times, FT.com. January 28, 2011.

crude oil prices will undoubtedly be volatile. They can fall well below current levels and projections, and TAPS will remain the only means to bring crude to market. Mr. Coulson explained at his deposition that he does not think any producer has abandoned a field that can yield 50,000 barrels per day and he was also unaware of any field that was abandoned at 20,000 barrels per day.[8] Additional investments such as the Strategic Reconfiguration (SR) and low flow conversion investments may be required. Regardless, there is a great deal of oil remaining and its unit or per barrel value is likely increasing over time. This makes the concept of economic obsolescence of TAPS virtually meaningless and irrelevant for assessing its economic value for many years to come.

7. Since the alternatives to TAPS are not economically feasible, producing oil in high-priced future markets will cause TAPS Owners to engineer and make other modifications to extend the life of TAPS in order to access the valuable crude remaining in mature fields. The Owners will also continue to work with the State to gain access to additional petroleum reserves in places such as Area 1002 of the Arctic Natural Wildlife Refuge (ANWR) and the Outer Continental Shelf (OCS). All of these make the notion of economic obsolescence or TAPS abandonment ludicrous. Perhaps even more to the point, I explain that the BP Royalty Trust filings with the Securities and Exchange Commission[9] estimate "continued economic production from the Prudhoe Bay field" until as far as 2075.[10] I explain below that the estimated economic life of Prudhoe Bay production is directly tied to the price of world oil as these British Petroleum (BP) 10-K Reports to the SEC confirm.

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[8] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc., et al. vs. State of Alaska et al, Case No. 3AN-06-8446 CI (consolidated); December 8, 2010; pages 123 and 124.

[9] See BP Prudhoe Bay Royalty Trust 10-Ks for the years 2003 through 2009.

[10] BP Prudhoe Bay Royalty Trust 10-K for period ending December 31, 2007, page 18.

8. I also review independent and mutually reinforcing reasons why I conclude that TAPS is an interdependent and integrated component of the Owners' upstream and downstream activities. TAPS is simply the only viable transportation system to move Alaska North Slope (ANS) oil and natural gas liquids to downstream markets. While other routes were considered, none have been built. There are no viable alternative transportation options for Alaska's northernmost petroleum reserves. TAPS from the beginning was unique. TAPS, without ANS crude oil, would have no purpose or utility. Similarly, ANS crude oil would have virtually no economic value without TAPS. The two assets are mutually advantageous. This synergy means TAPS and ANS petroleum are inseparable in terms of their true economic value.

9. In the following discussion, I address several tariff and disputed matters that have been thoroughly debated, litigated, and subjected to regulatory and legislative review. I do not intend or wish to reopen these matters in great detail. Rather, my purpose is to discuss their limited significance for reaching a conclusion that TAPS is an integrated component of Alaska's petroleum industry and that the Owners of TAPS treat it as an integrated component of their North American enterprise. These primarily involve the manner in which TAPS Owners have viewed the tariffs they pay themselves through intra-company transfers to use TAPS. I will explain that the Owners have front-end loaded cost recovery for the construction of TAPS, as well as the early recovery of future dismantlement, removal and restoration (DR&R) expenses, for the purpose of reducing taxes and royalties tied to netback or well-head value. Rather than supporting the notion that the current value of TAPS, other things equal, is lower because future tariffs might be less than they otherwise would have been, this regulatory treatment and history show

the exceptional degree of integration between these Alaskan oil assets and business units of the same parent corporation.

10. In my analyses I rely, in part, on the knowledge I gleaned from my participation as an expert for various interested parties in the 2005, 2006, and 2007 State Assessment Review Board (SARB) Hearings and in the 2009 judicial review of the 2006 SARB Decision. I have also done additional work in this matter to prepare this Report, including reviewing additional material, and I utilize my more than four decades of experience in regulatory matters, particularly as they are related to energy, economics, and financial matters. A list of the documents I considered in forming my expert opinion and/or that are attached to my Report as Exhibits is found in Appendix B.
11. I am being compensated at the rate of $550 per hour for my work in this matter.

II. THE ECONOMIC LIFE OF TAPS AND WHY OBSOLESCENCE IS FICTION

TAPS is an Integrated Part of a Vertically Integrated Petroleum Business in Alaska

12. As I explain below, the parent corporations that own TAPS treat it as an integral part of a vertically integrated petroleum business in Alaska. Even as throughput from core or base production on the North Slope declines, satellite production increases. Helene Harding of ConocoPhillips (COP) reported production for Kuparuk and Alpine that shows satellite extending offsetting the base declines.[11] Other areas are also being added and helping to replace declines in the original fields. Mr. Charles J. Coulson of BP Pipelines (Alaska) Inc. told the Federal Energy Regulatory Commission (FERC) in 2010 "…Prudhoe Bay and Kuparuk have played a dominant role in the past. Yet as they decline, the smaller oilfields will constitute a larger relative share of the total (but still declining)

[11] Helene Harding, Vice President North Slope Operations & Development, ConocoPhillips Alaska, "2010 North Slope Forecast for ConocoPhillips" Slides 4 and 5. RDC, November 18, 2009.

production."[12] In addition, the world's appetite and willingness to pay higher prices for crude have extended the economic life of TAPS and enhanced its value.

13. The Department of Energy's (DOE's) Annual Energy Outlook (AEO) 2011 Early Release Overview forecasts Reference Case crude oil prices in 2035 of $200 per barrel and real prices of $125 in 2009-dollars.[13] Others including BP's Chief Economist, Cristof Ruehl, expect a gradual price rise in crude but no spike given the existence of spare capacity in the industry.[14] Others are more bullish about the return of higher world crude demand and prices late this year and into 2012.[15] The value of TAPS is a function of reserve value, and both depend upon the price of crude oil to determine their economic life and viability. When West Texas Intermediate (WTI) crude oil was priced at $96.01 per barrel on December 31, 2007, BP estimated the economic production in Prudhoe Bay alone would last until 2075.[16]

14. The U.S. Department of Energy's official Energy Information Administration's (EIA) forecasts for light crude oil exceed the $96.01 that BP used. I prepared several charts to show the historic and future crude oil price projections. Attachment 1 shows the history of average annual crude price movements for WTI crude in both nominal dollars and real 2008 dollars since the discovery of productive reserves on the North Slope. This chart shows that as the world economies are recovering, the prices of crude oil are rising and

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[12] Testimony of Charles J. Coulson, FERC Doc. Nos. IS9-348-000 *et al*, page 6 of 24.

[13] Department of Energy, Energy Information Administration; Annual Energy Outlook 2011 Early Release Overview, page 3. www.eia.gov/forecasts/aeo/pdf/0383er(2011).pdf.

[14] Black_Jacobin, Guardian Media, The Trinidad Guardian; "Oil prices will rise gradually – BP's Ruehl", December 16, 2010

[15] See Hemmerling, Kurtis. "2011 Price of Crude Oil Forecast and Prediction," Suite 101.com, August 6, 2010; Moors, Dr. Kent. $150 Oil – Five Reasons Crude's Set to Double…and Five Ways You Can Profit: Oil and Energy Investor; AEO2011 Early Release Overview; Analysis and Projections (December 16, 2010).

[16] See BP Prudhoe Bay Royalty Trust 10-K for period ending December 31, 2007, page 18.

once again approaching the level that BP used to estimate the economic life of Prudhoe Bay production to 2075.

15. Attachment 2 contains three charts. The first shows the 2008 real price projections based upon the EIA's AEO 2010 high, reference, and low cases. The next two charts show the nominal forecasted prices adjusted for inflation. First, I show the nominal prices with a 3% inflation rate, which I consider to be a reasonable economic estimate. Next, I reduce the inflation rate to a more conservative 2.75%. Regardless, the forecasted 2035 price of crude would be above $100 per barrel in nominal terms.[17] The reference case's nominal price for 2035 exceeds $250 per barrel. The economic life of Prudhoe Bay will increase if, and more likely when, these higher future crude prices materialize.

16. There may be up and down movements. Nevertheless, the expectation for a prevailing upward trend is unassailable. The first chart in Attachment 3 shows the most recent EIA reference case, AEO 2011, relative to the AEO 2010 reference case. The near term forecasted prices are increased. In the second chart in Attachment 3, I show the combined price forecasts extended to 2075, the highest year that BP reported to the SEC when WTI prices had a value of $96.01 in the same 2008 real dollars used in this attachment.

17. In my on-going research on the determinants of crude oil prices, I have found that one of the more important factors is the amount of worldwide production spare capacity. For example, in the run-up in crude prices in 2008 to nearly $150 per barrel,[18] spare capacity was in the range of between about 1 million barrels per day and something less than 3

[17] On January 28, 2011, the Financial Times reported that crude oil hit $99.63 per barrel for the ICE March Brent. The Financial Times also explained that the anomaly for the all-time high $12 gap between Brent and WTI prices was due to exceptional inventories at Cushing, Oklahoma. See Blas, Javier and Richard Edgar, "Oil Near $100 as Mideast Tensions Grow." Financial Times, FT.com. January 28, 2011.

[18] EIA World Oil Prices and Production Trends, in AEO 2009.

million barrels per day.[19] Currently, the EIA estimates spare capacity at 4.65 million barrels per day.[20] Nevertheless, as world demand has surpassed the pre-recession levels, prices are once again trending up. One new concern is that nearly 81% of the estimated spare capacity is in Saudi Arabia. This concentration adds a new source of risk.[21] All things considered, increasing demand to new highs plus concerns with the concentration of spare capacity and other producing area political risks combine to create a strong bullish pressure on the continued upward trend in crude oil prices. This does not mean prices cannot and will not experience periods of decline. Further, government agencies that plan and budget the future must and should be very conservative and, in effect, not count future tax receipts until they nearly materialize. Accordingly, it is important to understand that State agencies responsible for budgets and financial planning necessarily are more cautious in their future price assumptions. Therefore, I do not consider such State revenue-related future price assumptions to even be representative of low future price projections.

TAPS' Value is Primarily Derived from the Crude Oil

18. TAPS value is derived from the crude oil, which is the economic driver of the pipeline's economic value. TAPS is the only gateway to the vast petroleum resources in Northern Alaska. Alternatives such as railroads, tankers, and other even less likely alternatives are neither feasible nor remotely economic. As I reported in my book on TAPS in 1972, oil tankers were not successful. Short of global warming speculation[22] that opens the Arctic

[19] Williams, James L. "Energy Economist: Oil Price Risk" January 25, 2011, page 5.
[20] Williams, James L. "Energy Economist: Oil Price Risk" January 25, 2011, page 5.
[21] Williams, James L. "Energy Economist: Oil Price Risk" January 25, 2011, page 6..
[22] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska), Inc., et al. vs. State of Alaska et al, Case No. 3AN-06-8446 CI (consolidated); December 8, 2010; page 127.

Ocean year-round, railroad tankers are the only option. The necessary scale is incredible. Ignoring the time and scale necessary to handle, load, and unload the crude oil shipped, the number of tankers and trains would be unprecedented for a region such as the 800 miles of mostly remote and complex Alaskan natural environment.

19. Railroad tank cars can carry about 30,000 gallons or about 700 barrels each and they are about 30 meters long. For every 100,000 barrels of oil shipped, a train 4,300 meters or about 2 2/3 miles long would need to depart the North Slope. Two lines or massive sidings to permit mostly empty tanker returns would be required, at least, in some locations. The lines would need to be maintained at a high level and snow and debris removal would be a major challenge. Permits for Rights-of-Way (ROW) and construction would be a major accomplishment. Other than to illustrate the unique role of TAPS and the lack of plausible substitutes, the rail option plays no serious role in the valuation of TAPS or for determining its economic life. Without TAPS, there is no, or very limited, resource value because there are no economically sensible or viable alternatives to TAPS. This was my primary conclusion in my 1972 book, and it remains unchanged today. Others agree. Without the oil resources, there would be no TAPS. It has always been operated and valued along with the petroleum reserves and upstream infrastructure investments as one integrated business. Putting aside minor distractions about relatively smallish incremental investments in TAPS, the increasing and expected future price of oil more than offsets reduced throughput under virtually all reasonable scenarios. Outside of proceedings about TAPS' assessed value and the Owners' ideation of little economic value and obsolescence, there are no signs that the Owners will abandon the oil reserves in the north.

TAPS' Economic Life

20. In 2008, the Owners commissioned a study, the Trans-Alaska Pipeline System Low Flow Investment Plan. This report has a throughput range of between 200,000 to 500,000 barrels per day, with a base forecast of 300,000 barrels per day in 2030.[23] This same report identifies various additional capital investments the Owners are considering.[24] Nothing suggests an early shutdown of TAPS. The report also considers even lower flows for TAPS below the midstream refineries that take crude from TAPS and decrease throughput. TAPS' lower portion, therefore, would operate at even lower flows than the oil that enters TAPS at Pump Station 1 if the refineries continue to draw down shipments from Pump Station 1. If the lower portion of TAPS can flow, the upper portion should flow also. The midstream refineries use royalty crude. If production falls, there will be less royalty-in-kind (RIK) crude available.[25] The crude available for the Flint Hills Refinery, rather than TAPS' throughput to Valdez, would likely be reduced. Furthermore, I think it is much more likely that these midstream refineries would shut down before TAPS if this step was necessary to continue to access even dwindling North Slope production for world markets. It might not be necessary to consider these conditions because, as BP explained, access to heavy crude could replace dwindling

[23] Decision Frameworks, Trans-Alaskan Pipeline System Low Flow Investment Plan – A Report on the Investment Decisions Needed to Address Low Flow Issues Through 2030, prepared for the TAPS Owners, page12; 8 August, 2008 Final Report. AY07AV030830-30903.

[24] Decision Frameworks, Trans-Alaskan Pipeline System Low Flow Investment Plan – A Report on the Investment Decisions Needed to Address Low Flow Issues Through 2030, prepared for the TAPS Owners, pages 26-30; 8 August, 2008 Final Report, AY07AV030830-30903.

[25] See Alaska Oil and Gas Report November 2009, page 36; Alaska Department of Natural Resources Division of Oil and Gas; "Best Interest Finding and Determination for the Sale of Alaska North Slope Royalty Oil to Flint Hills Resources Alaska, LLC", Alaska Department of Natural Resources Division of Oil & Gas, February 12, 2004; Bradner, Alan. "Potential Retroactive Payment Haunts Flint Hills Refinery." Alaska Journal of Commerce, May 21, 2006.

Prudhoe Bay production.[26] It also seems more than possible that national restrictions, particularly in the OCS fields, could diminish in the future. Therefore, future TAPS throughput is likely to be greater than worst-case assumptions.

21. The 2009 Appendices to the TAPS Owners' low flow study's worst case has the Pump Station 1 throughput at 177,000 barrels per day, with withdrawals for the North Pole refinery reducing the throughput downstream to 107,000 barrels per day. This pessimistic assumption of a 6% per year decline is about half the TAPS Owners' expected throughput in 2030 of 261,000 barrels per day after North Pole, and 331,000 barrels at Pump Station 1. Regardless, the worst case, which is less than the low flow analyzed, would not be a hard floor. At a value of $100 per barrel, the one-year value of the crude shipped would approach $4 billion. The estimated present value of TAPS investments to handle the low flows would have an undiscounted cost of $1.288 billion for the more than two decades of investments and operations. On a present value basis using 10% as a discount rate, the TAPS Owners' low flow study would cost less than a half billion dollars in 2008 dollars.[27]

22. There is further support in recent deposition testimony that in determining the economic life of the North Slope Fields, as well as the reserve estimates and production profile, "the only TAPS-related input is a tariff which BPPA provides BPXA."[28] Further, in response to a question about whether any of the inputs into BP's modeling have anything to do with the capacity of TAPS to continue to operate, Ms. Claire Fitzpatrick stated "The

[26] See "BP Alaska – Building a 50-Year Future." Bates No. BP07AVO002459. Designated as Confidential Material (see Deposition of Charles Coulson, Tr. 172 - 177.)

[27] Decision Frameworks, Trans-Alaskan Pipeline System Low Flow Investment Plan – A Report on the Investment Decisions Needed to Address Low Flow Issues Through 2030, Prepared for TAPS Owners (8 August 2008), AY07AV030830-30903; Decision Frameworks, Appendices to Trans-Alaskan Pipeline System Low-Flow Investment Plan (2009); AY07AV030623-30829.

[28] Deposition Transcript of Claire Fitzpatrick in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al., Case No. 3AN-06-8446 CI (Consolidated);page 26, lines 6-7 (December 31, 2010).

only input in relation to the pipeline is the tariff that BP Pipelines gives me which goes into the economic assessment."[29] The meaning is straightforward. The crude reserves and production are increasingly valuable even as throughput may decline. The costs to correct and maintain TAPS pales in comparison to the value of the oil shipped on TAPS.

23. In 2001 the Owners applied to extend the TAPS Right-of-Way (ROW). In their applications,[30] the Owners used three concepts:

    i. Design Life, which the Owners explained was extended due to "robust components" and "state-of-the-art updating strategies".

    ii. Physical Life, which the Owners "considered virtually unlimited given the execution of appropriate surveillance, maintenance, repair, and replacement programs".

    iii. Economic Life that is governed by recoverable petroleum reserves.

The useful life of TAPS is drawn from the volume of reserves and, as BP explains in its 10-K Royalty Trust SEC filings,[31] the future price of WTI crude. I would add the cost of development and production, as well as the cost of delivering the crude to markets.

24. I prepared a chart and some simple regressions in Attachment 4 to show the relation between economic life and WTI prices that BP relies upon in its various recent SEC 10-K filings. I plotted the relationship between the estimated life of the Prudhoe Bay reserves and WTI year-end prices. In particular, I found that for every $10 increase in year-end WTI prices, the economic life of Prudhoe Bay increases about 5.5 years. (See the linear

[29] Deposition Transcript of Claire Fitzpatrick in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al., Case No. 3AN-06-8446 CI (Consolidated);page 27, lines 2-7.

[30] State and Federal Applications for Renewal of the Trans Alaska Pipeline System – Duration of the Right-of-Way Renewal for the Trans Alaska Pipeline System (March 23, 2001) (MUN-736); Exhibit 3 to Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI (Consolidated); (December 8, 2010), page 9..

[31] See BP Prudhoe Bay Royalty Trust 10-Ks for the years 2003 through 2009.

regression in Attachment 4.) Furthermore, Ms. Fitzpatrick explained that the year-end prices are not the same as "BP's internal assumptions."[32] I concluded that with higher internal price forecasts, such as EIA's reference case or estimates attributed to BP's Mr. Cristof Ruehl, the economic life of Prudhoe Bay and other fields in northern Alaska would be extended. Without alternative transportation options, this would necessarily increase the economic life of TAPS. For example, recall that BP estimated a productive life to 2075 based upon $96 per barrel.[33] Using the simple regression and EIA's AEO 2011 forecast for 2035 of about $125 per barrel in 2008 real dollars would extend BP's 2075 estimated productive life to about 2090.

TAPS is Not Facing Economic Obsolescence

25. Therefore, there is no likelihood that the Owners would abandon TAPS or that TAPS is facing economic obsolescence. For example, a city may zone housing and require duplex units to be built. At the outset, a duplex owner might collect $10,000 per unit per year, or $20,000 with both units rented. Imagine a future where the demand for duplexes shifts and only half the units are rented. However, also assume that rental values, given other economic factors, jump to $25,000 per year. In this future world, the owner has more rental income with half the occupancy rate. The owner also has a valuable future option or opportunity to rent the second unit if demand increases in the future. There has been no economic loss or obsolescence. The owner will not abandon the duplex and it is worth more today than when originally built according to the zoning requirements then in effect.

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[32] See Deposition Transcript of Claire Fitzpatrick in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI (Consolidated); page 31, lines 7-20; December 31, 2010.
[33] BP Prudhoe Bay Royalty Trust 10-K for period ending December 31, 2007, page 18.

26. I expect that economic recovery in the U.S. would add about 2 million barrels of demand alone if we return to our pre-recession demands of more than 20.7 million barrels per day from the 2009 levels of about 18.7 million barrels per day.[34] These would be added to the continuing growth in consumption in China and India.[35] The International Energy Agency (IEA) reports that world consumption increased 2.7 million barrels per day in 2010 from 2009 to 87.7 million barrels per day. The IEA forecasts 2011 consumption to be 89.1 million barrels per day and 2014 consumption to be 92.3 million barrels per day.[36] All these demand estimates exceed the pre-recession record consumption level of 85.3 million barrels per day in 2007.[37] The robust price increases and growing consumption mean there should be no weight attached to any false and misleading claims anyone makes related to TAPS' impending obsolescence, and even less for any notion the Owners will abandon their Alaskan reserves.

27. See "Highly Confidential" paragraph sent under separate cover to: Ken Diemer, Rob Johnson, Mauri Long, Craig Richards, Robin Brena, Ralph Palumbo, and Paula Hinton.

28. Money must be invested in the industry, but the returns of and on these investments taken in the integrated manner they are viewed mean that Owners and Alaska will remain in the oil business. It is easy to see why this is so. Alyeska Pipeline reports on its website that more than 15 billion barrels of oil have been transported over the 33 years since it began flowing in 1977.[38] In August, 2007 the DOE and National Energy Technology Laboratory (NETL) reported optimistic estimates of "economically recoverable" oil

[34] U.S. Energy Information Administration, Short-Term Energy Outlook, released Jan. 12, 2010.
[35] BP Statistical Review of World Energy June 2010.
[36] "IEA Raises Oil Demand Forecast." Canadian Broadcast Corporation News. January 18, 2011; "OPEC, IEA Differ on Demand Outlook Due to Assumptions, IEF Says." Bloomberg.com. January 23, 2011; Oil Mixed After IEA Warning on USD 100 Price." OneIndia News. January 19, 2011.
[37] Williams, James L. "Energy Economist: Oil Price Risk." January 25, 2011.
[38] Alyeska Pipeline Service Company Website; www.alyeska-pipe.com.

reserves with high oil prices and natural gas development of 35 to 36 billion barrels of oil for the 2005 through 2050 period.[39] Without ANWR 1002, this drops to about 29.5 billion barrels. If Chukchi Sea OCS is also omitted, the reserves' estimate drops to 19.5 billion barrels. The further removal of the OCS Beaufort Sea along with ANWR and Chukchi OCS would reduce the DOE/NETL 2005 to 2050 economically recoverable estimates to about 15.5 billion barrels, which is about what TAPS has shipped to date. Even removing natural gas development on top of the other exclusions would leave about 9.5 billion barrels. At even today's price estimates, the remaining reserve value is easily measured in trillions of dollars. You do not need to be an optimist to understand why the Owners and their valuable TAPS lynchpin are going nowhere.

29. In 2004, the U.S. Department of the Interior published its "Environmental Assessment of the Proposed Reconfiguration of the Trans-Alaska Pipeline System."[40] Two observations in this report are particularly relevant. First, competitive pressures exist for shippers to improve operating efficiencies. Second, the report found that details were not final. Nevertheless, the proposed 2002 reconfiguration was cleared of environmental impacts for an additional 30 years, taking TAPS operations until at least 2032.[41] Couple this with SARB's 2045 and DOE/NETL findings discussed above and the chances of obsolescence, despite uncertainty, are low to virtually impossible.

30. Alyeska Pipeline published its Long Range Plan (LRP) on June 1, 2010. This LRP includes two facts that make premature obsolescence a most unlikely possibility or even a

[39] Department of Energy/National Energy Technology Laboratory, "Alaska North Slope Oil and Gas – A Promising Future or an Area in Decline." Page viii, August 2007.
[40] U.S. Department of the Interior – Bureau of Land Management. "Environmental Assessment of the Proposed Reconfiguration of the Trans-Alaska Pipeline System; EA-03-009, BLM Serial Nos. AA-5847 and FF-12505, January 2004.
[41] U.S. Department of the Interior – Bureau of Land Management. "Environmental Assessment of the Proposed Reconfiguration of the Trans-Alaska Pipeline System; EA-03-009, BLM Serial Nos. AA-5847 and FF-12505, January 2004.

reasonable assumption. First, throughput in 2011 is set at 615,000 barrels per day in 2011 in the LRP.[42] This equals about 225 million barrels per year, which at $100 per barrel would be worth about $22.5 billion dollars. In 2020, the LRP uses 420,000 barrels per day.[43] This would exceed 153 million barrels of annual throughput in ten years and, depending on the value per barrel in 2020, the throughput would be worth many billions of dollars.

31. Second, the LRP shows the Owners investing and expensing many billions of dollars over the next five-year and following five-year period to keep this valuable Alaska petroleum resource flowing to market through TAPS. Alyeska reckons that during the next five years, the Owners will expense about $2.63 billion.[44] About 14.4% of this expense would be for major maintenance and electrification/automation. Alyeska also plans $870,365,000 in additional capital investments over the next five years.[45] In the second five years, 2016 through 2020, Alyeska plans to expense about $2.38 billion and make $420,000,000 in additional capital expenses.[46] Total cash outlays for the next ten years would be about $6.3 billion. The planned throughput and outlays make it a virtual certainty that TAPS is not facing a premature shutdown or early obsolescence.

III. TAPS IS AN INSEPARABLE PART OF A FULLY INTEGRATED BUSINESS

TAPS is Mutually Interdependent With Petroleum Reserves and Production

[42] Alyeska 2011 Long Range Plan, June 1, 2010, Bates No. AY07AV045412-469, page 8.
[43] Alyeska 2011 Long Range Plan, June 1, 2010, Bates No. AY07AV045412-469, page 8.
[44] Alyeska 2011 Long Range Plan, June 1, 2010, Bates No. AY07AV045412-469, page 20.
[45] Alyeska 2011 Long Range Plan, June 1, 2010, Bates No. AY07AV045412-469, page 20.
[46] Alyeska 2011 Long Range Plan, June 1, 2010, Bates No. AY07AV045412-469, page 21.

32. The previous discussion outlines some of the reasons why TAPS and northern petroleum reserves and production are mutually interdependent with each other. There are also other specific reasons for concluding that TAPS is an integral part of the Owners' Alaskan oil business. These are:

i. Over the past forty years, various consolidations and mergers in the oil industry demonstrate the inherent and integrated relationship between TAPS ownership and specific corporate interests in ANS petroleum resources as well as production and downstream in the North American and global markets. Similarly, various sales and ownership transfers also demonstrate the same inherent and integrated relationships between TAPS and ANS petroleum. I can find no major integrated oil company transaction that was influenced or driven by a firm seeking to garner tariff income from their ownership of TAPS. Instead, the value of TAPS and its economic power comes from the crude reserves on the North Slope and, potentially, resources in other parts of Northern Alaska.

ii. As explained, the world has an increasing appetite for crude oil. Even with sluggish but somewhat improving macroeconomic conditions, the price of crude is heading back to $100 per barrel. This is 50 times the world price when TAPS was being developed in 1972 and 25 times the higher U.S. price. Many are talking about crude hitting $150 with worldwide economic recovery.[47] My personal estimates are in this range. I base them on four factors: (i) an increase in U.S. consumption of at least 2 million barrels per day

[47] Moors, Dr. Kent. $150 Oil – Five Reasons Crude's Set to Double…and Five Ways You Can Profit; AEO2011 Early Release Overview; Analysis and Projections (December 16, 2010).

by 2012/13; (ii) increased demand in China and India; (iii) weakness in the dollar relative to other currencies; and (iv) general price increases and inflation due to unprecedented government budget deficits. There would be no economic obsolescence related to reduced throughput at even lower future crude prices. Two facts drive the value of TAPS in use: (1) the entire Alaskan oil enterprise is fully integrated; and (2) higher prices trump declining volume. The latter (declining volume) is also less certain than the likelihood of rising crude prices.

iii. Governance and business operations are fully integrated with other aspects of North Slope operations. These are determined at the corporate level or at least a level well above the Alaskan entities that are assigned to work with Alyeska. These units are small and operationally insignificant. These are reasons to conclude that the governance and business operations of TAPS are fully integrated with other aspects of various Owners' corporations. Furthermore, there is no truly independent or stand-alone governance of TAPS. Mr. Coulson explained the voting in the Operating Committee to the FERC. A 66 2/3 Owners voting interest is affirmatively required from three or more Owners. This vote is need for capital investments and operating costs, except for some "small items that fall within Alyeska's discretionary spending authority."[48]

iv. The Owners all benefit from an increase in TAPS tariffs. Past increases in tariffs reduced their state severance and royalty payments. Third party shippers were squeezed out of Alaska because they had to pay higher tariffs. The true parent Owners of TAPS do not treat TAPS as a stand-alone business

[48] See Testimony of Charles J. Coulson, FERC Doc. Nos. IS9-348-000 *et al*, page 14.

unit. The TAPS operator, Alyeska, works for the parent corporations, and the local TAPS affiliate of each Owner simply preserves a fiction that TAPS is a stand-alone business. The entire petroleum industry knows who owns TAPS.

v. Pricing and the nominations or volume offered are not rational or competitive for a stand-alone pipeline, but pricing behavior is rational from an integrated perspective (*e.g.* not reducing rates to compete for a greater share of decreased throughput). The Owners of ANS typically do not sell their crude production to third parties upstream of TAPS because this would allow the third parties to nominate shipments to a non-affiliate of the seller. Mr. Coulson attempted to justify and did not dispute the "strong" pattern of shippers (*i.e*. producers) transporting their crude on their affiliated pipeline company's portion of TAPS. Furthermore, most sales of ANS crude are downstream on an as-delivered basis beyond Alaska. This bundling of oil, pipeline, storage at Valdez, and shipping demonstrate the integrated nature of the Alaskan oil industry to the extent that the "products" are integrated into a bundled as delivered product. This is unique and is not the case in the lower 48.

vi. History is repeating itself. The current corporate posturing for ANS natural gas, as well as for the ownership and control of a new natural gas pipeline, demonstrate that the Owners believe that it is impossible or not in their interests to separate the ownership of upstream petroleum resources and a single viable natural gas pipeline. As with TAPS, the North Slope natural gas reserves and future natural gas pipeline will determine the economic value of the other.

33. In the early 1970s I wrote a book: Alaskan Oil: Alternative Routes and Markets.[49] I explained and documented the integrated nature of TAPS and how the Owners would use these interdependencies to their advantage. In fact, these relationships were fully understood and not disputed in any of the various federal and state debates related to TAPS. I found, for example, there was evidence that the Owners had plans to export Alaskan crude and use these volumes to increase more profitable imports on the East Coast as "import for export" offsets at a time when foreign oil imports were restricted under the Mandatory Oil Import Quota program. I also found support for a plan where the Owners would ship Alaskan oil to Central America for shipment to the U.S. Virgin Islands. This would avoid the Jones Act, which required using U.S.-owned ships for shipments between U.S. ports. This would have reduced shipping costs, and the Owners could have also recorded a sale to themselves at the lower world crude oil prices in the U.S. Virgin Islands. These steps would combine to reduce "net back" values on Alaska's North Slope. This would reduce royalty and severance payments. The combined effect would be more profitable than simply shipping Alaskan crude to the West Coast, which had healthy crude oil production in the late 1960s and early 1970s. Facts and circumstances changed and evolved. Regardless, the Owners' initial assessments demonstrate the integrated value and importance of TAPS. Their subsequent actions demonstrate that their appreciation and understanding of this integrated value assessment has not wavered. I concluded that the Owners and U.S. federal officials fully understood the vastness of Alaskan crude production/reserves and its integrated North American and global value and significance.

[49] Baltimore, Maryland: The Johns Hopkins University Press, 1972.

Mergers and Consolidations Demonstrate Integration

35. Some subsequent actions also support this conclusion. First, there have been some notable consolidations and mergers that demonstrate the importance of North Slope petroleum coupled with ownership in TAPS. Since the discovery of crude oil on the North Slope and the decision to build TAPS, British Petroleum (BP) acquired Standard Oil of Ohio (SOHIO). The two companies had been linked since 1969 when BP signed an agreement with SOHIO whereby BP transferred to SOHIO its leases at Prudhoe Bay in exchange for 25 percent of SOHIO's equity. By 1978, with increasing throughput on TAPS, BP became a majority shareholder in SOHIO, eventually acquiring the remaining 45 percent of equity in 1987.[50] This consolidation expanded eastern U.S. oil interests into the West Coast and was directly tied to Alaskan oil resources and TAPS. BP was a crown corporation of the government in the United Kingdom when it began its quest into Alaska and the lower 48 states. It has become a retailer and vertically integrated oil company in the U.S. as a result of the SOHIO acquisition and its relatively dominant position in Alaskan oil and ownership of TAPS. Atlantic Richfield, or ARCO, was formed with the 1966 merger of Atlantic Refining and Richfield Petroleum. Atlantic's first service station opened in 1915 in Pittsburg, Pennsylvania, and Richfield's first service station opened in Los Angeles in 1917. ARCO became primarily a regional west coast player after the 1966 merger[51] based, in large part, on the firm's Alaskan resources.

36. In April 1999, BP and ARCO announced their intent to merge. In November 1999, Alaskan Governor Knowles announced that he had reached agreement with BP on a Charter to Develop the Alaska North Slope. However, the Alaska State Legislature's

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[50] See "History of SOHIO" and "BP Merged With Standard Oil of Ohio, An Early Player in What Turned Out to Be the Alaskan Oil Boom" at www.bp.com.

[51] See "History of ARCO/AMPM" www.bp.com.

Merger Committee rejected the Charter Agreement because it did not require BP to divest what it considered to be a sufficient portion of ARCO's assets to ensure competition in Alaska. The Federal Trade Commission (FTC) also filed suit to enjoin the merger. That lawsuit was suspended when BP agreed to sell to Phillips Petroleum all of ARCO's Alaska assets.[52] This eventually made ConocoPhillips the second largest TAPS Owner and a major owner of ANS reserves.

37. Chevron and Unocal completed their merger in August 2005 after a rival bid from the China National Offshore Oil Company (CNOOC) was rejected.[53] This merger added Unocal's 1.36% interest in TAPS to Chevron's holdings. Chevron traces its roots back to 1879 with the discovery of oil just north of Los Angeles. The company was originally called Pacific Coast Oil Co. That company subsequently became Standard Oil Company of California, and then Chevron. Chevron acquired Gulf Oil Corporation in 1984, a merger that about doubled its worldwide proven oil and natural gas reserves. In 2001, Chevron acquired Texaco. But it was the merger with Unocal that allowed Chevron to gain a foothold in Alaska. Chevron is one of the world's largest fully integrated global energy companies.[54] It operates on six continents and more than 20 different countries, including the U.S. In addition to its ownership in TAPS, Chevron also started an exploratory drilling program at the White Hills prospect on the North Slope.[55]

38. The merger of Exxon and Mobil was completed on November 30, 1999,[56] joining two of the companies that had been created when the U.S. Supreme Court dissolved Standard

[52] See Alaska State Legislature End of Session Press Packet, Second Session 21st Legislature Republican-led Majority, "BP Amoco/ARCO Merger Summary (May 4, 2000).
[53] See Chevron Press Release "Chevron Enhances Growth Strategies with Unocal Merger" August 10, 2005.
[54] See Chevron Company Profile at www.chevron.com.
[55] See Chevron Company Profile at www.chevron.com.
[56] See "Our History" www.exxonmobil.com/Corporate/history/about_who_history.aspx.

Oil and split it into 34 companies. ExxonMobil is the third largest Owner of TAPS. The merger with Mobil expanded Exxon's presence in California's retail gasoline business.[57] ExxonMobil is organized around three global operating divisions: (1) Upstream, which consists of oil "exploration, production, transportation and sale of crude oil and natural gas;"[58] (2) Downstream, which "manufactures and sells petroleum products;"[59] and (3) Chemicals.[60]

39. None of these moves likely would have happened at the values exchanged "but for" their thorough understanding of the scale of the merging companies' TAPS investments, the value of ANS crude oil, and the integrated nature of TAPS with upstream ANS oil reserves and production, coupled with west coast marketing and refining. At the same time, tariff income was not a major and likely not even a *de minimis* reason for these mergers.

40. It is not a surprise that absent any regulatory restraints that the three primary Owners of TAPS (ExxonMobil, ConocoPhillips, and BP) also own most of the crude oil production on the North Slope. These three primary Owners have a combined 95.56% interest in TAPS.[61] In 2009, the same three Owners had 91.4% of the estimated production on the North Slope. And their proportion of ANS production is expected to grow in the future.

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[57] To secure regulatory approval for the merger, Exxon was required by the FTC to divest 340 Exxon stations in California. In 2000, Exxon completed this requirement by selling its California stations to Valero Energy Company. ExxonMobil continues to operate over 700 Mobil branded retail outlets in California. See "ExxonMobil" at http://en.wikipedia.org/wiki/Exxon_Mobil, page 4.
[58] See ExxonMobil 10-K for fiscal year ended 12/31/2009, page 67.
[59] See ExxonMobil 10-K for fiscal year ended 12/31/2009, page 28.
[60] See ExxonMobil 10-K for fiscal year ended 12/31/2009, page 4.
[61] ExxonMobil (46.93%), ConocoPhillips (28.29%) and BP (20.34%) combined to own 95.56% of TAPS. See Alyeska: About Us; www.alyeska-pipe.com/about.html.

For example, in 2005 the DOR forecasted that in 2050, these “Three” could own 96.8% of the production on the North Slope.[62]

The Owner’s Actions Throughout the Life of TAPS Demonstrate Integration

41. TAPS is FERC-regulated, despite its intrastate nature. This is an exception to the normal regulatory rule, which demonstrates the economic importance and uniqueness of TAPS in conjunction with the important North Slope petroleum reserves for the nation. More important, despite the essential facility and no competitive-alternative characteristics of TAPS, the Owners have been granted extraordinarily light-handed regulation, enjoying significant and unprecedented regulatory treatment at FERC. One possible justification is the rather undeniable observation that TAPS is a very significant integrated component of the nation’s petroleum industry. The following discussion reviews the special advantages afforded TAPS.

42. The TAPS tariffs have been a source of controversy, as I explain in greater detail in Section IV. The primary Owners have succeeded over much of TAPS’ life in keeping the prices of their respective regulated tariffs well above typical regulated prices that are more strictly tied to cost-of-service (COS) regulatory principles. I have reviewed various BP memos[63] written in the late 1970s when BP was contemplating TAPS tariff matters. These show that BP understood the benefit from increasing TAPS tariffs to reduce upstream royalties and production taxes. This would include more rapid depreciation and accelerated DR&R recovery. These memos also demonstrate that shippers with less TAPS ownership, as well as SOHIO, would prefer lower tariffs. Finally, they show BP

[62] See 2005 DOR Fall Revenue Sources Book, production forecast and 2005 DNR/DOG unit/lease ownership information sourced from “Alaska Oil and Gas Report May 2006”, Alaska Department of Natural Resources.

[63] BP Pipelines Inc Confidential Memorandum from F.K. Rickwood to D.A. Lewis dated May 20, 1977, and Memorandum from A.J. Barrett-Miles to D.A. Lucas dated March 15, 1977.

understood the value of using TAPS as part of an integrated worldwide petroleum entity in BP's Interstate Commerce Commission (ICC) rate filings.

43. BP discussed in a May 1977 memorandum[64] the reasons why the TAPS Owners should file a high tariff rate. First, BP observed "as balanced/shipper/owners, ARCO, Exxon (and possibly Phillips) should file a high tariff in order to minimize the combined government income from the field and the pipeline."[65] In effect, BP recognized the advantages provided to BP from being part of an integrated system. As part of an integrated system, BP observed that a high tariff would decrease government income from the field and pipeline while increasing the Owners' cash flow from the field and pipeline.[66] And the cash flow consequences were not trivial. BP estimated that each $1/bbl price difference from a $7.25/bbl tariff would change BP's income by about $93 million over the 1977-1978 period.[67] Ironically, some thirty-one years later, Exxon-Mobil argued against the tariff terms proposed by TransCanada and Foothills pipeline in their Alaska Gasline Inducement Act (AGIA) license application, asserting that the State of Alaska would be harmed under the proposed relatively high natural gas tariff prices that "increase the shipper's transportation costs, thus reducing the ANS wellhead netback prices upon which the State's royalties and taxes are calculated."[68] ExxonMobil and TransCanada have since moved together on the Alaska Pipeline Project that is now

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[64] BP Pipelines Inc Confidential Memorandum from F.K. Rickwood to D.A. Lewis dated May 20, 1977, and Memorandum from A.J. Barrett-Miles to D.A. Lucas dated March 15, 1977.

[65] BP Pipelines Inc Confidential Memorandum from F.K. Rickwood to D.A. Lewis dated May 20, 1977, and Memorandum from A.J. Barrett-Miles to D.A. Lucas dated March 15, 1977, page 1.

[66] "As balanced shippers, ARCO, Exxon (and possibly Phillips) should file a high tariff in order to minimize the combined government income from the field and the pipeline…. For example, a $1/bbl increase in tariff increases cash flow from field and pipeline by 10.8¢/bbl, providing there is a corresponding $1/bbl decrease in wellhead prices." BP Pipelines Inc. Confidential Memorandum from F.K. Rickwood to D.A. Lewis dated May 20, 1977, page 1.

[67] BP Pipelines Inc. Confidential Memorandum from F.K. Rickwood to D.A. Lewis, dated May 20, 1977, page 6.

[68] ExxonMobil Corporation Comments on TransCanada AGIA License Application, at 5 (March 6, 2006).

available for "open season" negotiated access. The other two major Owners of TAPS, BP and Conoco Phillips, back the Denali Gas Pipeline.[69] Nothing is final. However, the signs of a greater government role in financing and guarantees would make any of the natural gas alternatives quite different than the privately financed TAPS.

44. Higher tariff prices benefited the parent corporations of the integrated shippers who were also the TAPS Owners. Mr. Charles J. Coulson, current President of BP Pipelines (Alaska) Inc. explained in discussing "integrated profitability" in recent deposition testimony that "every affiliate is expected to optimize with its affiliates."[70] A higher TAPS tariff paid to an affiliate would reduce royalties and severance taxes. These unusual tariff provisions made it possible for the Owners to recover their investment in TAPS earlier than would have been possible if the tariffs had instead been tied to the expected economic life of TAPS. It also allegedly had the effect of reducing the income of non-integrated producers and, in some cases, causing these competitors to sell their Alaskan assets. For example, Conoco owned an interest in Milne Point but did not have an ownership interest in TAPS. However, the high tariff rates on TAPS made it less economic for Conoco to produce the oil from its interest in Milne Point and, in 1988, it shut in this production. In 1993, Conoco gave up its interest in the Milne Point field when it traded its interests in the Milne Point properties and the Badami field to BP for properties in the Gulf of Mexico.[71] Commenting on trading Milne Point to BP, Conoco President and Chief Executive Archie Dunham stated "We traded all our Milne Point properties in Alaska to BP…. It broke my heart to trade Milne Point, but we had to do it.

[69] Investopedia. "The Alaskan Pipeline Conundrum." April 16, 2010.
[70] See Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI (Consolidated); (December 8, 2010), page 57.
[71] New York Times; "Conoco and British Petroleum to Swap Assets", Section 1, page 43; Column 1; Financial Desk; November 6, 1993.

All the value of that property was taken away from us in the pipeline tariffs."[72] BP, which in effect simply transferred the profit on the high tariff price from one corporate subsidiary to another, did not have the same constraints in producing crude from Milne Point because of the integrated nature of the North Slope operation. The Milne Point transaction again demonstrates the integrated nature of the North Slope production and transportation operations and the advantages that this integration provides to the entities that own both production and transportation assets in Alaska.

45. The impediments TAPS' high tariff prices impose on non-integrated producers on the North Slope have been in effect for decades. As I discussed above, high TAPS tariff prices benefit affiliated producers/carriers because they reduce royalties and severance payments to the State. Effectively, one affiliate pays the high tariff to another affiliate, and the tariff does not represent a true cost. This is not true for independent producers for whom the tariff does represent a real cost. Consequently, high tariff prices have curtailed independent privately owned operators on the North Slope. Tariff income is a regulatory construct, not an economic one. Tariff income does not affect economic value any more than rent controlled apartments reflect value in use. Regardless, future TAPS tariffs are uncertain and cannot be reasonably relied upon to determine present value. Furthermore, TAPS is essentially the straw in the middle of an integrated system composed of production, transportation, and tankers. Along with the price of crude oil, these other factors are much more important in determining the economic value of TAPS. Without TAPS, none of these upstream and downstream assets and businesses would be in place, profitable, or valuable.

[72] "Getting to the Future First," *Hart's Oil and Gas Investor,* August 1996 (Vol. 16, No. 8), page 41.

46. The Owners do not fundamentally disagree. Indeed the Owners' witness at the FERC concluded:

> TAPS is not a typical market situation. Most of the oil moves under transactions among affiliate companies. These affiliate relationships are a major factor in determining carriers' incentives to reduce tariffs.[73]

Dr. Jaffe made this statement in support of the Owners' efforts to reduce TAPS available or nominal capacity to expected throughput. Dr. Jaffe's statements fully support the conclusion that TAPS is completely integrated with the Owners' complete Alaskan petroleum businesses. The strong preference for affiliates to do business together was also described above in Mr. Coulson's more recent 2009 testimony to FERC on behalf of BP.[74]

47. The Regulatory Commission of Alaska (RCA) recognized the integrated relationship between upstream production and transportation on TAPS in Order 151 in the P-97-4 docket. The Order considered, among many other things, the appropriate debt equity structure to use when setting rates on TAPS. Concluding that TAPS, as a stand-alone pipeline, could have attracted debt financing, the RCA observed "Sohio financed its participation in TAPS almost exclusively with debt…In effect, SOHIO 'bet the company' on the success of its North Slope venture. To secure its debt SOHIO pledged all its assets to its creditors. SOHIO's ability to finance its TAPS expenditures rested largely upon lenders' valuation of its reserves in the ground."[75] Thus, the reserves created a combined

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[73] Affidavit of Dr. Adam Jaffe in *Exxon Pipeline Co, et al.*, Application of TAPS Carriers for Approval of Amended and Restated Capacity Settlement Agreement; FERC Docket No. OR96-1-000 et al., page 15.
[74] Affidavit of Dr. Adam Jaffe in *Exxon Pipeline Co, et al.*, Application of TAPS Carriers for Approval of Amended and Restated Capacity Settlement Agreement; FERC Docket No. OR96-1-000 et al., page 15.
[75] Order 151, *In the Matter of the Correct Calculations and Use of Acceptable Input Data to Calculate the 1997, 1998, 1999, 2000, 2001, and 2002 Tariff Rates for the Intrastate Transportation of Petroleum Over the Trans Alaska Pipeline System Filed by Amerada Hess, et al.*, Docket No. P-97-4, at 72, line 16 through page 73, line 2, citing WBT-27 (Gary) 34 (November 27, 2002).

pool of credit during the construction phase of TAPS. Financing was readily available because the upstream production and the midstream transportation were considered to be part of one integrated Alaska operation. On August 1, 1974, The British Petroleum Company Limited "unconditionally" guaranteed "the liabilities and obligations" of both Sohio Pipeline and BP Pipelines Inc. to the United States. This guarantee and others discussed below are consistent with the absolute need for the parent corporations to provide financial support for TAPS. This guarantee covers "all additions, amendments, supplements, extensions or renewal of TAPS' Right of Way authorization."[76] This all demonstrates that TAPS is an integrated, not a stand-alone, asset.

48. See "Highly Confidential" paragraph sent under separate cover to: Ken Diemer, Rob Johnson, Mauri Long, Craig Richards, Robin Brena, Ralph Palumbo, and Paula Hinton.

49. Another source of potential abuse is related to the manner in which capacity units are defined. Individual Owners take separate nominations for their own capacity and are able to submit bids for another Owner's capacity. TAPS capacity is restricted to expected (or nominal) volumes, not the actual physical capacity conditions. And each Owner operates its portion as though it was an independent common carrier pipeline,[77] including both the volumes it ships for its affiliates and the volumes that exceed its affiliate's requirements. The TAPS Owners can restrict independent producers' access to transportation by limiting the volume made available through nominations. One way to do this is that, as Mr. Coulson explained, he thinks BP currently nominates 100 percent of its production to its affiliated BP Pipeline.[78]

[76] See Guaranty. BP07AV-FR-102038 – 041.
[77] TAPS operates as a joint-venture pipeline, where each owner files a separate tariff for its share of the line.
[78] Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI; (December 8, 2010), page 57

50. Another source of concern is potential market power due to the concentration in ownership. The three largest TAPS Owners combine to have market shares in TAPS that exceed 95 percent.[79] This is also known as three-firm concentration of 95 percent. In addition, they represent a market Herfindahl-Hirschman Index (HHI)[80] of more than 3,400.[81] The FERC and Department of Justice have found that for oil pipelines, markets with an HHI of less than 1,000 are not concentrated, markets with an HHI between 1000 and 1,800 are moderately concentrated and markets with an HHI above 1,800 are concentrated and not competitive.[82]

51. BP's market ownership share for a unique essential facility is about 50 percent and the top three combine to have a market share of 95 percent. This represents market power, which increases the likelihood of anomalous bidding, and other similar and anti-competitive mid-stream behavior increases sharply. In particular, it would be possible for "low-priced" capacity to remain unused, while "high-priced" capacity is over-subscribed. For example, Amerada Hess owned a 1.5% interest in TAPS, but sold its production interest in 1996. At that point, Amerada Hess was dependent on other producers/shippers to fill its capacity on TAPS. Amerada Hess reported that beginning in June 1999 "gross throughput had dropped to the point where BP, Amoco, Exxon, and ARCO no longer found it economic to volume cascade and began full affiliate tendering." As a result, Amerada Hess Pipeline Corp. lost 90% of its throughput.[83] Amerada Hess reported that

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[79] BP Pipelines (Alaska) Inc. owns 46.93%; ConocoPhillips Transportation Alaska Inc. owns 28.29%; and ExxonMobil Pipeline Company owns 20.34%. Two minor owners, Unocal Pipeline Company and Koch Alaska Pipeline Company own 1.36% and 3.08% respectively. Source: Alyeska Pipeline website www.alyeska-pipe.com/about.html.

[80] The HHI measures market concentration and is calculated by squaring the market shares of each firm competing in the market and then summing the squares.

[81] $46.93^2 + 28.29^2 + 20.34^2 +1.36^2 + 3.08^2 = 2{,}202.42 + 800.32 + 413.72 + 1.85 + 6.16 = 3{,}424.47$

[82] See for example, U.S. Department of Justice and Federal Trade Commission Horizontal Merger Guidelines §1.51.

[83] See Amerada Hess Write-Down Exhibit Bates Number RTSTAH100060-61, at 51-52, December 2, 1999.

in order to attract volumes to its unused capacity on TAPS, it lowered its shipping tariff price below the tariff prices the integrated shippers charged. However, even with this aggressive pricing strategy, Amerada Hess was unable to attract any interest in the volumes offered.[84] Amerada Hess reported that it subsequently had to write off the pipeline and use a useful life of zero.[85]

52. The Owners often act in a manner that is not rational for multiple competing owners of a stand-alone pipeline. For example, Alyeska Pipeline Services Company reports that on January 14, 1988, TAPS hit a peak throughput of 2,145,297 barrels per day and effectively since TAPS has operated below this installed capacity.[86] Under competitive conditions with multiple owners and excess capacity, it is economically logical to expect price discounting to gain additional shares of shipments from non-affiliated shippers. The Owners did not do so. This was not rational competitive behavior for a stand-alone pipeline with multiple owners, but can be understood in the context of a pipeline that is part of an integrated Alaska petroleum operation that can charge non-Owners more and pay the State of Alaska less tax, if tariffs remain high and are merely intra-company transfers between affiliates.

53. There are two allegations downstream from Alaska that are tied to TAPS ownership. First, the TAPS Owners market and sell ANS crude on an "as delivered" or "fully bundled" basis, which means the Owners do not allow a competitive refiner to secure crude on the North Slope and separately contract for TAPS capacity or Valdez

[84] See Amerada Hess Write-Down Exhibit Bates Number RTSTAH100060-61, at 51-52, December 2, 1999, page 52.

[85] See Highly Confidential Response of Amerada Hess Pipeline Corporation to Rebuttal Interrogatory No. 98(b) of Tesoro Alaska Company in RCA Dockets P-97-4 and P-97-7 (March 26, 2001), referencing Amerada Hess Write Down Exhibit, Bates Number RTSTAH 100060-62.

[86] Alyeska Pipeline Service Company, The Facts, History TAPS, pages 67 and 88 (2009); www.alyeaska-pipeline.com/pipelinefacts.html.

operations/shipping. A refinery seeking ANS crude must, for example, pay the Owners of TAPS to deliver the crude to its lower 48 states refinery. This also means that the Owners also control the sale of crude at the well head, control downstream port and shipping services, and bundle their various prices into an “as delivered” product.

54. Second, other than State royalty crude oil, the primary Owners have virtually effectively prevented any of their ANS crude from being sold to Alaska’s independently owned and operated refineries. Again, “fully bundled” delivered crude oil marketing demonstrates two things. First, there is downstream market power. TAPS is integrated with other Alaskan oil functions and services. Mr. Coulson explained to the FERC the rationale for the shippers nominating to ship crude on their affiliates’ portion of TAPS “by thinking about the integrated corporate economies. When an upstream affiliate ships barrels in its pipeline affiliate’s space, it pays the published tariff rate to the pipeline affiliate, and no money leaves the affiliated group. The payment is essentially a transfer within the corporate family.”[87] TAPS is not now and has never been a stand-alone business.

55. The three primary Owners operate and manage their interest in TAPS in an integrated fashion. While their management and corporate governance differ, none of the three primary Owners manage or treat TAPS as a stand-alone business enterprise.

56. For example, in its SEC Form 20-F filed for the fiscal year ending December 31, 2009, BP described in some detail the integrated nature of its operations. BP corporate retains the power to control the financial and operating policies of any of its subsidiaries. BP operates as a global group through its subsidiaries, which are divided into two segments; (1) Exploration and Production; and (2) Refining and Marketing. The Exploration and

[87] See Direct Testimony of Charles J. Coulson, BP Pipelines (Alaska), Inc., et al., FERC Docket No. IS09-348-000 et al., page 21 April 16, 2010).

Production segment "covers three key areas. Upstream activities include oil and natural gas exploration, field development and production. Midstream activities include pipeline transportation and processing activities related to…upstream activities. Marketing and trading activities include the marketing and trading of natural gas…Refining and Marketing's activities include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and petrochemicals products and related services."[88] BP stated that "group functions and regions support the work of our segments and the required integration and coordination of group activities in a particular geographic area and represents BP to external parties."[89] Thus, while BP centrally and globally controls the segments, the regional head also acts to control BP's upstream and midstream operations as one integrated business segment. And, BP noted that one of its "most significant midstream pipeline interests" includes the Trans Alaska Pipeline System.[90]

57. BP Pipelines has always been part of the entire BP group. For example, in an internal 1977 memo, BP was struggling to devise a way to justify what would have amounted to a 40% return of BP Pipeline's equity based on the pipeline's 85/15, debt/equity structure.[91] D.A. Lucas suggested to A.J. Barrett-Miles that BP could present the "equity return in a more favorable light" if BP claimed that "BPP is part of the whole BP group which is subject to a more stringent D/E constraint of about 50/50. Hence, as the funds of BP Pipelines can be considered to belong to the group's finance pool, the BP group's capital structure should be used. This would lower the effective return on equity to about

[88] BP Form 20-F for period ending 12/31/2009, page 6.
[89] BP Form 20-F for period ending 12/31/2009, page 6.
[90] BP Form 20-F for period ending 12/31/2009, page 18.
[91] Internal BP Memo, dated March 15, 1977, from D.A. Lucas to A.J Barrett-Miles.

20%."[92] This demonstrates that pipeline operations are understood to be part of a larger integrated business operation and that BP was not hesitant to admit this fact when it was in its financial interests to do so. BP Pipelines has also attempted to include costs associated with employees of affiliated companies in its proposed rates. The RCA has found that there is "scant evidence that they provide services related to TAPS operations."[93] Regardless, this demonstrates that BP considers the employees of any of its Alaska operation to be part of one large integrated operation. More recently, Mr. Coulson admitted that BP Pipelines (Alaska) did not have a checking or bank account and that an upstream segment executive group, not BPPA, approved TAPS' budgets.[94]

58. Conoco Phillips treats its Alaska operation similarly to the way BP does. Margaret Yaege, the President of Phillips Transportation Alaska, testified before the RCA and confirmed that Phillips Transportation holds a 28 percent interest in TAPS.[95] She testified that Phillips Transportation Alaska owned Conoco Phillips' interest in TAPS, but that the employees were "grouped with the Lower 48 pipeline company employees."[96] Ms. Yaege did not know whether she was "an employee technically of the pipeline" or Conoco Phillips as a corporation.[97] She did testify that she has "a group in Alaska that works for me. That group in Alaska, it's quite a small group of people and we manage all of the Alaskan pipeline assets for Conoco Phillips."[98] Finally, Ms. Yaege testified that Phillips Petroleum Alaska, Inc., the entity that owns Conoco Phillip's

[92] Internal BP Memo, dated March 15, 1977, from D.A. Lucas to A.J Barrett-Miles.
[93] Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings, etc., P-03-4(34) June 10, 2004, page 27.
[94] Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al., Case no 3AN-06-8446 CI; (December 8, 2010), pages 40–43.
[95] Hearing transcript of Margaret Yaege's testimony in Docket P-03-04, page 915, lines 9-11.
[96] Hearing transcript of Margaret Yaege's testimony in Docket P-03-04. page 914, lines 12-17.
[97] Hearing transcript of Margaret Yaege's testimony in Docket P-03-04, page 914 lines 22-25.
[98] Hearing transcript of Margaret Yaege's testimony in Docket P-03-04, page 920, lines 4-6.

interest in TAPS, does not have any employees,[99] but she was not sure which Conoco Phillips entity the people in her group worked.[100] BP Pipeline (Alaska)'s president, Mr. Coulson, seemed to know that his compensation came further upstream than BP's TAPS affiliate.[101] It speaks volumes about the integrated nature of the management and operations in Alaska that a key Conoco Phillips' employee was not sure which entity actually employed her.

59. The RCA also rejected Phillips Transportation Alaska Inc.'s attempt to include significant costs for affiliate filing expenses based on about three nominations per month for crude oil in a process described by a Conoco Phillips witness as akin to making "hotel reservations."[102] Nevertheless, attempting to allocate such costs suggests the extent to which Conoco Phillips considers its Alaska operations to be one integrated operation.

61. Conoco Phillips' SEC Form 10-K for the fiscal year ending December 31, 2009, further demonstrates the integrated nature of the Conoco Phillips' Alaska operation. The Form 10-K discusses Conoco Phillips six business segments. One of those segments, Exploration and Production, is described as producing, transporting, and marketing crude oil, natural gas, and natural gas liquids on a worldwide basis.[103] This reflects the fact that Conoco Phillips considers the upstream production and midstream transportation functions to be part of the integrated Exploration and Production business segment throughout the world including Alaska.

[99] Hearing transcript of Margaret Yaege's testimony in Docket P-03-04, page 916, line 17.
[100] Hearing transcript of Margaret Yaege's testimony in Docket P-03-04, page 920-23.
[101] Deposition Transcript in Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI (Consolidated); (December 8, 2010), page 33.
[102] Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings, etc., P-03-4(34) June 10, 2004, at 28.
[103] ConocoPhillips 10-K for the fiscal year ended 12/31/2009, page 1.

62. Conoco Phillips does not treat Phillips Transportation Alaska, Inc. separately from its other Alaska operations. Ms. Yaege also testified that she could not "recall a board of directors meeting for PTAI."[104] She further testified that she had never seen a balance sheet or financial statement for Phillips Transportation Alaska, Inc., had never signed a Phillips Transportation Alaska, Inc. check, and in fact, did not even know if that entity had its own banking account or whether it banked through Conoco Phillips.[105] Ms. Yaege also testified that her salary was allocated between the four pipelines that Conoco Phillips operated in Alaska and the Prudhoe Bay assets that she managed, which she described as "the production side of the business."[106] Conoco Phillips was not treating Phillips Transportation Alaska, the subsidiary that owned its interest in TAPS, as anything other than as an integral part of one integrated system. Conoco Phillips Transportation, Alaska, Inc., and Conoco Phillips Alaska also maintain principal offices at the same address. Further, the slate of directors for each company is identical,[107] again demonstrating the integrated nature of Conoco Phillips' Alaska operation.

63. Exxon Mobil approaches corporate governance and reporting somewhat differently. Exxon Mobil places all its pipeline operations into a single North American business unit called Exxon Mobil Pipeline. It also groups together its other vertical business units, such as refining, production and exploration, and marketing, etc. into separate business units. Exxon Mobil Pipeline is divided into nine business units arranged by geography and product type. TAPS is contained within the Joint Interest Business Unit. In addition to TAPS, this business unit includes the Wolverine Pipe Line, Plantation Pipeline, Mobil

[104] Hearing Transcript of Margaret Yaege in Case P-03-04, page 915, lines 21-25.
[105] Hearing Transcript of Margaret Yaege in Case P-03-04, page 918, lines 5-21.
[106] Hearing Transcript of Margaret Yaege in Case P-03-04, page 1111, line 18.
[107] Conoco Phillips filing with the Alaska Corporations Business and Professional Licensing, Department of Commerce (1/22/09).

Eugene Island Pipeline (MEIPL), Yellowstone Pipeline, and others.[108] The Operations Control Center/Scheduling Department for these nine business units is located in Houston, Texas.[109] While vertical functions are managed separately, TAPS is not a stand-alone investment. It is part of a global pipeline business unit. ExxonMobil does not govern, operate, or treat TAPS in a stand-alone manner.

64. Alyeska is the agent/operator of TAPS. The TAPS Owners direct it and five out of the six TAPS Owners have no pipeline employees.[110] A BP witness stated, "Alyeska actually operates the TAPS, but as you said, we manage our interest in TAPS which is huge. We have a lot of money invested in TAPS and we definitely want to work with Alyeska."[111] In fact, Ms. Yaege of ConocoPhillips testified that the Owners' Committee must approve Alyeska's expense and capital budget.[112] The RCA rejected the TAPS Owners' 2001-2003 TSM Intrastate Filings, finding that "BP's proposed rates may be burdened with allocations of owner direct costs that are incurred to monitor and manage an investment rather than to operate TAPS."[113] This further demonstrates the integrated nature of the Owners' Alaskan operations.

65. The shippers and TAPS Owners did not maintain any semblance of separation when discussing tax matters with the State of Alaska. For example, James Greeley testified at the 2008 SARB Hearing for TAPS that he dealt with the same person for the shipper and Owner. Mr. Greeley stated in response to a question whether the Owners owned any

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[108] ExxonMobil Pipeline website at www.exxonmobilpipeline.com.
[109] ExxonMobil Pipeline website at www.exxonmobilpipeline.com.
[110] Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings, etc, P-03-4(34) June 10, 2004, at 27, lines 9-12, referencing Exhibit A to *Tesoro Alaska Company's First Motion for Summary Disposition or, in the Alternative, Motion for Partial Summary Judgment on Particular Issues,* filed November 20, 2003; and each TAPS Carrier's response to T-68(a), T-75(a), T-80(a), T-87(a), T-90(a) and T94(a).
[111] Id. at 27, referencing the testimony of BP witness, Mr. Foster.
[112] See Transcript of Yaege testimony in RCA Docket P-03-04 page 946, lines 3-4.
[113] Order Rejecting the TAPS Carriers' 2001-2003 TSM Intrastate Filings, etc., P-03-4(34) June 10, 2004) page 27, lines 12-14.

fields, reserves or oil replied "your tax representatives – that we send these letters to are the same representatives for the shippers as for the carriers…I talked to the same person for the chippers that I do for the TAPS Owners, and they have that information available to them."[114]

66. I find it very compelling that Exxon Mobil's public posturing and statements stress the importance of integration during debates related to natural gas pipeline development,[115] The views expressed concerning a future natural gas pipeline extraordinarily were very transparent. Start with the vast reserves of natural gas on the Alaskan North Slope. These have been partially used over the past thirty-plus years to enhance crude oil production through injection and to increase TAPS throughput. This was initially accomplished using enhanced oil recovery and more recently by blending natural gas liquids with crude oil in the TAPS transportation system. There is a readily apparent two-way interdependence between TAPS utilization and operations and the upstream petroleum production and resource development decisions of the primary corporate TAPS Owners and their various integrated petroleum activities in Alaska.

67. In the previous proceedings I offered my opinion that the Owners (Conoco Phillips, Exxon Mobil, and BP) of the natural gas leases on the North Slope have been adamant about their demands as to what they want before they will agree to develop North Slope natural gas fields. Specifically, the Owners refuse to sell natural gas until an off-slope

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[114] Transcript of SARB HEARING - TAPS, VOLUME 1, page 237, lines 2-10 (May 20, 2008).

[115] See ExxonMobil Corporation Comments on TransCanada AGIA License Application (March 6, 2005), Comments of Marty Massey, ExxonMobil's U.S. Joint Interest Manager, to the Alaska Legislature House Resources Standing Committee on House Bill No. 177 (Alaska Gasline Inducement Act) (April 17, 2007), and Anchorage Daily News article "Conoco Stresses Need for Tax Promises on Gas Pipeline" January 8, 2008.

pipeline is built.[116] Since 1999, the Alaska Gasline Pipeline Authority (AGPA) has attempted to purchase North Slope natural gas from North Slope producers, including Exxon Mobil. Those efforts have proven to be futile and no deal has been struck to sell North Slope natural gas to the AGPA.[117]

68. Further, the Owners have also been unwilling to commit natural gas to any such natural gas pipeline unless the State makes concessions with respect to royalty and taxes. For example, in the 15th Plan of Development (POD), the Unit Operator suggested that State concessions in royalty and tax requirements would assist in improving the economic feasibility of a North Slope natural gas pipeline.[118] In testimony before the Alaska State Legislature on April 12, 2007, Mr. Marty Massey, U.S. Joint Interest Manager for Exxon Mobil Corporation, testified that in order to proceed with the pipeline, ExxonMobil "will need some things from the State."[119] These "necessary things" included fiscal terms that are predictable and durable."[120] However, Mr. Massey did not limit his requests to predictable and durable fiscal terms for natural gas. In discussing the massive investments that the Alaska Gas Pipeline Project would involve, Mr. Massey stated, "increases in taxes on oil and gas related activities during the life of the project could significantly impact the commercial viability of the project and offset the benefits of

[116] The Unit Operator for the Point Thompson Field files Plans of Development (PODs) that detail development of the Unit. In those PODs, the Unit Operator has repeatedly justified the lack of development of the Unit on the lack of a major off-slope pipeline. For example, in 1983, at 2 in the 7th POD, Exxon stated that "Further development prior to the commencement of construction of a pipeline to market would constitute economic waste through premature expenditure of funds which otherwise could be utilized for exploratory or development activity on other Alaska areas and leases." More recently, in 1998 in the 15th POD, Exxon stated "hurdles to economic development remain; particularly high well and facilities costs, lack of a gas market and transportation system…Consequently, development of the Thompson Sand gas is not economically justified at the present time." page 1.

[117] See Attachment C (Affidavit of William M. Walker dated March 21, 2008), Brief of Alaska Gasline Port Authority on Remand by Superior Court Order Dated December 26, 2007; *In re Remand Proceedings Pursuant to December 26, 2007 Order of Superior Court Regarding Point Thompson Unit Agreement,*

[118] 15th POD, page 1 (1998).

[119] See Alaska State Legislature House Resources Standing Committee, page 15 (April 12, 2007).

[120] See Alaska State Legislature House Resources Standing Committee, page 15 (April 12, 2007)..

taking on a project of this magnitude."[121] Mr. Massey, in effect, demanded fixed taxes on gas and oil-related activities during the life of the project.[122]

69. The Owners consider the production and transportation aspects of the oil and natural gas businesses to be part of the fully integrated pipeline/transportation operations. The Owners seek to gain a benefit for the production side as a *quid pro quo* for building a pipeline to transport the natural gas because they realize that natural gas without a pipeline to transport it is of little value.[123] In other words, the production and transportation functions are fully integrated components of one Alaskan operation. This same dichotomy is also apparent in the crude oil business in Alaska. The Owners have been reluctant to enter into natural gas purchasing agreements that would allow a downstream purchaser to ship the natural gas on any pipeline that is independently owned and they have refused to enter into firm transportation commitments to ship their gas on a third-party pipeline. For example, ExxonMobil's comments in 2008 on TransCanada's AGIA Application are illuminating.[124] ExxonMobil stated that it "appreciates TransCanada's suggestion that anchor shippers should be involved as co-owners, so as to have better alignment of interests. However, as explained in ExxonMobil testimony to the Alaska legislature during April 2007, because AGIA disconnects the upstream and the midstream aspects of the business, Exxon Mobil's participation in an AGIA-related

[121] See Alaska State Legislature House Resources Standing Committee, page 16 (April 12, 2007)..

[122] See Alaska State Legislature House Resources Standing Committee, page 16 (April 12, 2007).

[123] The Alaska Department of Revenue estimates the prevailing price of natural gas delivered to the North Slope area of $0.940/Mcf of natural gas pursuant to 15 AAC 55.173(a)(2) for the first quarter of 2009. This is much less that the average spot price at Henry Hub during January of 2009 of $5.40/Mcf and February of $4.65 /Mcf. Sources: Alaska Department of Revenue, Tax Division; www.tax.alaska.gov/programs/documentviewer/viewer/aspx?425o; EIA Short Term Energy Outlook, March 2009.

[124] ExxonMobil Corporation Comments on TransCanada AGIA License Application (March 6, 2008).

project would be difficult."[125] In effect, the Owners want to duplicate for natural gas a fully integrated system, along with the myriad of attendant benefits, which they created for ANS crude oil with TAPS. In my opinion, the Owners want participation plus government concessions and subsidies. The latter were not particularly part of the construction of TAPS. It is conceivable that there could be some sort of compromise. Regardless, this relation between petroleum resources on the North Slope and a dedicated pipeline demonstrate the undeniable high degree of interdependence and integration, whether through ownership under TAPS or some hybrid approach for natural gas.

IV. THE TAPS TARIFF REFLECTS FULL INTEGRATION BUT NOT FULL ECONOMIC VALUE

TAPS Tariffs Reflect Integration

70. The TAPS Owners have successfully used various favorable, regulated tariff provisions for many years. In fact, BP recognized the importance of receiving favorable tariff treatment in the early years of TAPS' operation. Initially, BP recognized the value of setting tariffs as high as possible, stating "Alaska will endeavor to force the Interstate Commerce Commission to decrease the pipeline valuation and/or the Owners' tariffs, probably with some success. Accordingly, the higher the tariff filed initially probably the higher will be the tariff finally agreed with the ICC."[126] BP also observed "oil pipeline regulations are relatively favorable now, but this is expected to change for the worse in coming years. Therefore, the owners should want to maximize cash flows before the

[125] ExxonMobil Corporation Comments on TransCanada AGIA License Application (March 6, 2008) page 5.
[126] BP Internal Memo from F.K. Rickwood to D.A. Lucas, page 2, dated May 20, 1977.

rules of the games are changed."[127] And this is exactly what the Owners did: they maximized their cash flow by charging the highest possible tariffs they could.

71. BP blatantly explained the steps that it could take to convince its affiliate SOHIO not to depart from the other Owners' plans by filing low tariffs because this would increase State tax and royalty payments at the well-head and cause downward pressure on the tariff prices the other Owners could charge. BP observed that if Sohio filed a low tariff rate, "SOHIO would likely anger the other owners who…should still want to file a high tariff."[128] While falling short of suggesting outright collusion in setting tariff prices at rates that would be mutually beneficial, BP observed that if SOHIO does not toe the line, "the enmity which SOHIO would earn form the other owners could have adverse consequences for SOHIO"[129] and asks the ominous question: "Does SOHIO realize how big a game it is now playing."[130]

72. Moving ahead, the 1985 TAPS Settlement Agreement resolved tariff disputes for the first nine years of operation. The Owners agreed to refund $200 million to the State of Alaska for the 1982-1984 period, but made no refund for the prior years of operation.[131] For the period subsequent to 1984, the Agreement established the TAPS Settlement Methodology (TSM). The TSM established a method for determining the maximum tariff an Owner could charge. Through 1989, the Owners calculated tariffs by trending both the equity and debt portions of rate base. In 1989, when the Owners had recovered approximately 80% of their initial investment, the TSM shifted from an accelerated depreciated rate base

[127] BP Internal Memo from F.K. Rickwood to D.A. Lucas, page 2, dated May 20, 1977, page 2.
[128] BP Internal Memo from F.K. Rickwood to D.A. Lucas, May 20, 1977, page 3.
[129] BP Internal Memo from F.K. Rickwood to D.A. Lucas, May 20, 1977, page 4.
[130] BP Internal Memo from F.K. Rickwood to D.A. Lucas, May 20, 1977, page 4.
[131] The U.S. Supreme Court had previously rejected the TAPS owners' efforts to limit refunds if FERC found the tariffs to be excessive. *Trans Alaska Pipeline Rate Cases (Mobil Alaska Pipeline Company, et al. v. United States, et al.* 436 U.S. 631, 56 L.Ed. 591 (June 1978).

to an inflation-adjusted allowance per barrel basis to determine Owners' income. This effectively severed TAPS profit calculations from rate base.[132] This change kept the TAPS tariff high because the Owners were able to avoid the price reductions that a vanishing rate base would virtually universally cause to occur.[133] Thus, as the prices based on rate base were set to decline, FERC approved an after-tax $0.35 per barrel real return that was adjusted from 1983 to each subsequent year, including 1990, for inflation. This would equate to about $0.77 per barrel grossed-up for taxes in 1990. This allowance per barrel the Owners have been able to collect is not related to cost, increases Owners' profits, and also reduces the amount paid to the State.

73. I have also reviewed the State of Alaska and Department of Justice's (DOJ's) "Explanatory Statement" for TSM in FERC Docket No. OR-78-1, et al. The new tariff approach that FERC approved with the TSM kept the Owners' subsequent tariffs higher, increased integrated company cash flow, and reduced royalty and severance taxes on the ANS. This unprecedented mid-course change in tariff regulation from a cost-of-service like standard to an allowance per barrel standard demonstrates the extent to which the TAPS Owners understood and treated TAPS as their integrated lynchpin in Alaska. Two statements clearly prove the integrated nature of TAPS in Alaska's petroleum industry. First, the State and DOJ explain that their support for the settlement reflects the importance of "a declining tariff profile over the life of TAPS to encourage exploration

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[132] State of Alaska and United States Justice Department, *Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offer* (Federal Energy Commission, Docket No. OR 78-1, June 28, 1985 page 6.

[133] See, for example, the deposition transcript of Dr. Thomas Horst (testifying for the State of Alaska) where he testified that the after-tax, 35-cent-per-barrel allowance indexed for inflation increased the rates of TAPS relative to what they would have been under a TOC or DOC methodology. Deposition Transcript of Dr. Thomas Horst in Docket No. IS05-82-002 et al, page 204 lines 11-17 (September 13, 2006).

and development of the North Slope petroleum resources."[134] Second, the State and DOJ seek "an incentive to operate TAPS after its initial investment has been substantially depreciated.[135] Both these reasons demonstrate the integrated nature of TAPS for upstream petroleum development. They also support the conclusion that TAPS' value is by no means that of a "stand-alone" pipeline.

74. Another aspect of TAPS integration with the Owners' other Alaskan businesses is that the Owners have also benefited from FERC light-handed regulation. They successfully were able to pre-collect cash for such things as DR&R and accelerated depreciation. Much of this pre-collected cost recovery does two things: (1) it has worked to reduce the "but for" current and future tariff income; and (2) these TAPS-related pre-collected funds have been and remain available to the TAPS Owners and their parent corporations to generate additional income, reduce the corporate owners' finance costs worldwide, and provide additional opportunities for returns on invested capital for TAPS. In addition, the higher initial TAPS prices transferred value to the TAPS Owners from independents, which have, at least partially as a result of the TAPS tariffs and treatment, largely disappeared from the North Slope.

75. The Owners have often disagreed about issues such as the TAPS Quality Bank, Pooling Agreements, Capacity Allocation Agreements, Drag Reducing Agent (DRA) Agreements, penalty payments, and agreements on the injection of Natural Gas Liquids into the petroleum stream. The Owners have also attempted to collect charges for the

[134] State of Alaska and United States Justice Department, *Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offer* (Federal Energy Commission, Docket No. OR 78-1, June 28, 1985, page 3.

[135] State of Alaska and United States Justice Department, *Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offer* (Federal Energy Commission, Docket No. OR 78-1, June 28, 1985 page 6.

Exxon Valdez Oil Spill Settlement Costs and Payments and to assign costs for affiliate employees that are not in any way associated with pure pipeline functions. Some of these matters affect the way in which various regions of the North Slope are developed and the net amount each affiliated producer will be paid for its crude and natural gas liquids.[136] In other words, these tariff agreements represent a way for the producer affiliates to manage and maximize the value of their upstream assets using TAPS tariffs for leverage to gain competitively and reduce their State taxes. Similarly, they have used agreements concerning tankers and storage penalties at Valdez to manage their downstream assets with TAPS connecting the integrated parts. The various Owner attempts to manipulate the TAPS tariff all point conclusively to the fact that TAPS is part of one large integrated Alaska operation for the affiliated Owners of TAPS. It is a thinly veiled fiction to assert that TAPS is a stand-alone pipeline. To the contrary, it is the lynchpin of the affiliated Owners' Alaska integrated operations. Quite simply, the Owners often have used TAPS to gain at the expense of other businesses and the State.

Tariff Income Does Not Reflect the Owners' True Economic Value for TAPS

76. The tariff income related to TAPS does not reflect its full economic value to the Owners. The resource Owners would fight any attempt to take away the integrated economically valuable and viable pipeline away from the parent corporations that own the petroleum resources.

77. The Owners' true economic value for TAPS reflects both the value of the product shipped, as well as all the other benefits associated with ownership, including any regulatory outcomes or assets that add current and future economic value. These many

[136] For example, the pumpability factor makes it more expensive to ship heavier crude oil and the Quality Bank establishes differences in market value for different crudes.

and varied current and future additional regulatory enrichments provide the Owners with financial and economic benefits that they currently and expect to continue to enjoy. The expected future cash flow and tariff income that the pipeline generates is merely a portion of the value that TAPS will continue to generate for the pipeline Owners. In addition, there would be other integrated values that would flow through upstream and downstream vertically integrated oil companies. In discussing the integrated values of the pipe and upstream petroleum resources in 1971, a University of Alaska Report reached a similar conclusion: "…the long-term impact of North Slope oil will come mainly from production revenues. It is not correct, therefore, to attribute all or most of the projected growth to the proposed pipeline as such…"[137]

78. The value to the TAPS Owners would include the tariff income,[138] and the added value they have derived from (1) light-handed regulation; (2) DR&R; (3) accelerated depreciation; (4) understated production and life of the pipeline; and (5) taxes. This is, however, just the tip of the iceberg and does not represent TAPS full economic value.

79. The TAPS Owners have previously convinced the FERC to charge shippers for the future costs of DR&R. This is not an unusual regulatory tariff policy. That said, in my experience, regulators virtually always recognize that the pre-collected cash should be put to use to earn a return for consumers, not shareholders, so that future customers would pay less to achieve whatever level of decommissioning expense is required at the end of the asset's life. This has not been strictly applied in the case of TAPS.

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[137] Tussing, Arlon R., George W. Rogers, Victor Fischer, with Richard B. Norgaard and Gregg K. Erickson, Alaska Pipeline Report, Institute of Social, Economic, and Government Research, University of Alaska, Fairbanks, Alaska (1971).

[138] The U.S. General Accounting Office has observed that "Despite long-standing economic regulation, pipeline companies have been allowed to enjoy profits higher than those of the other most profitable industries." *Petroleum Pipeline Rates and Competition – Issues Long Neglected by Federal Regulators and in Need of Attention* (Washington, D.C.: General Accounting Office, July 13, 1979, page 12.

80. The Alaska Public Utilities Commission (APUC) opened Docket P-86-2 with respect to the Intrastate Settlement Agreement in the initial TAPS tariff proceeding.[139] Petro Star filed a petition to intervene and the APUC opened a docket to investigate the rates challenged by Petro Star. When Petro Star settled with the TAPS carriers in 1993 and withdrew its Petition to Intervene, the APUC found that there was no remaining ratepayer protest and stated that it had "previously accepted rates specified in the TAPS Settlement for periods prior to July 11, 1986, and accepted the TAPS Settlement Agreement to the extent that the TAPS Carriers were required to file rates calculated under the TSM set out in the TAPS Settlement Agreement in future years."[140] This meant that the TSM rates filed for the period 1986 through 1993 were still subject to APUC investigation, but only with respect to whether those rates were "correctly calculated under TSM and included acceptable input data."[141] These rates included DR&R.

81. Tesoro protested the TAPS tariffs in December 1996 that were proposed to go into effect on January 1, 1997, and asked the RCA to expand the scope of Docket P-86-2 to examine the justness and reasonableness of the 1986-1996 rates. The RCA declined to do so, recognizing that its predecessor, the APUC, had ruled that the TSM was "an acceptable method to calculate intrastate rates for 1986 to 1996."[142] However, the RCA concluded that it had opened Docket P-97-7 to consider protests over the amounts collected for DR&R.[143] The RCA set TAPS rates for 1997-2000 exclusive of DR&R considerations.[144]

[139] Order P-77-8(85)/P-77-9(79)/P-77-10(77)/P-78-5(70)/P-86-2(1) dated July 7, 1986.
[140] Order P-86-2(41)/P-86-3(7)/P-90-1(12), dated October 29, page 3.
[141] Order P-86-2(41)/P-86-3(7)/P-90-1(12), dated October 29, page 3.
[142] Order P-86-2(68)/P-97-4(165)/P-97-7(124)/P-03-4(16), dated June 24, 2003.
[143] Order P-86-2(68)/P-92-2(30)/P-94-1(36)/P95-1(16)/P-97-4(1)/P-97-5(1)/P-97-6(1)/P-97-7(1), dated June 27, 1997.
[144] Order P-97-4(151) and Order P-97-4(159)/P-97-7(118), dated April 18, 2003.

82. Subsequently, in a pre-hearing conference on May 1, 2003, the TAPS carriers filed a Statement with the RCA to the effect that they would forego DR&R collections in rates for 1997 through 2003, and all future DR&R collections until an Owner requested and received approval from the RCA to collect additional DR&R, and further agreed to waive all DR&R collections for the period 1997-2003. The RCA required the Owners to file a statement identifying the amount of DR&R collected, from whom the DR&R amounts were collected, and when the DR&R amounts were collected. In addition, the RCA ordered the Owners to guarantee an "obligation to pay refunds, if any, due shippers for over collection of DR&R funds, including over collection caused by the accumulated interest on and tax treatment of already collected DR&R amounts."[145] However, the RCA declined to investigate any potential over collections "in the middle of the line" stating, "until DR&R is complete, we will not know whether refunds are due."[146]

83. However, in Docket P-97-4 the RCA found that "the Carriers have collected $1,552,743,000 from 1977-1996 to cover their costs of eventual DR&R.[147] Previously, the Owners and the Internal Revenue Service (IRS) signed a Closing Agreement on Determination Covering Specific Matters in July 1988 relating to deductions with respect to DR&R costs. Under this agreement, "the owners and their successors in interest shall be allowed an aggregate deduction of $900,000,000 with respect of DR&R costs with respect to TAPS."[148] This Agreement allowed each Owner to deduct a part of the $900,000,000 in proportion to its ownership interest over the 318 months (July 1, 1977 through December 31, 2003) that TAPS would be operating. However, in Docket P-97-

[145] Order P-97-4(166)/P-97-7(125)/P-03-4(17), dated June 30, 2003.
[146] Order P-97-4(166)/P-97-7(125)/P-03-4(17), dated June 30, 2003 at 9.
[147] Order P-97-4(155), dated November 27, 2002, page 157.
[148] IRS Closing Agreement on Determination Covering Specific Matters, July 25, 1988.

4, the RCA found that "the Carriers have collected $1,552,743,000 from 1977-1996 to cover their costs of eventual DR&R,[149] an amount that exceeded the IRS Agreement's DR&R allowable deduction by $652 million.

84. I also reviewed Mr. John F. Brown's FERC testimony in Docket No. IS05-82 et al., where he explained accelerated depreciation and DR&R rate recovery, as well as other tariff-increasing aspects of the TSM. Most importantly, Mr. Brown concluded that with respect to DR&R, the Owners "over-collected by nearly $11 billion at the end of the pipeline's economic life, even after providing for estimated costs of dismantlement and removal of TAPS and restoration of the TAPS right-of-way by the end of 2037."[150]

85. The TAPS Owners' pre-collected DR&R amounts have been excessive. More important, the money collected has been passed up to the respective vertical corporate treasuries to be available to shareholders. In effect, there is <u>no</u> comparable TAPS lock-box or even a reasonable reduction of the current regulatory rate base or revenue requirements to compensate shippers for these pre-paid dollars and the returns they generate for the TAPS Owners. I suspect that with such adjustments, the shippers would be paid to ship, which would be ridiculous. Nevertheless, this points to the degree that TAPS has overcharged shippers and reduced payments to the State. The TAPS Owners have also been granted regulatory approvals to recover an extraordinary amount of accelerated depreciation up front. I am unaware of any similar cost of service regulation of this type of regulatory treatment of accelerated depreciation.

86. The premature recovery of DR&R and accelerated depreciation expenses reduced the ANS crude's net-back value at the wellhead. These also combined to increase the TAPS'

[149] Order P-97-4(155) page 157, dated November 27, 2002.
[150] Prepared Direct Testimony of John F. Brown on Behalf of Anadarko Petroleum Company, Tesoro Corporation, and Tesoro Alaska Company, before the FERC in Docket No. IS05-82-000, et al. page 4 (December 7, 2005).

Owners' free cash flow, which increased their respective after-tax cash flow and value. Shippers paid higher TAPS transportation prices. With less net-back value, the State's taxes were reduced, further increasing the Owners' upstream income and reserve value.

87. The last two examples explain how the TAPS Owners have profited at the expense of independent producers, royalty owners, and the State of Alaska's severance tax receipts. In fact, the RCA found that the TSM methodology "has, on a cumulative basis, provided the Carriers with an opportunity to recover $9.9 billion more than their costs as determined by the Depreciated Original Cost (DOC) revenue requirements. In 1997 dollars, the net present value of the cumulative stream of revenue requirement differences is $13.5 billion."[151] Adjusted for the purchasing power of money using the CPI, this $13.5 billion represents $18.1 billion in value for the three principal Owners of TAPS. Adjusted for the T-Bill rate, this $14.5 billion represents $19.2 billion in value for the three principal Owners of TAPS. These were not used to benefit independent shippers. This is not how regulators would and have typically performed.

88. Every dollar that the TAPS Owners, as shippers, pay their pipeline affiliates is not simply a wash because their extra dollars reduce royalty payments and severance taxes and cause the independent shippers to pay more. Furthermore, a telegram from BP Alaska to BP London, dated May 27, 1977, succinctly explained the U.S. tax machinations, which would permit TAPS Owners to reduce broader corporate tax obligations.

> Actual taxes, however, are determined by use of tax depreciation and after subtracting tax loss carry forwards (interest expensed during the construction period, which can be carried forward for 7 years, i.e. tax loss carry forwards). Further, actual tax liabilities can be reduced each year by up to 50 percent through use of investment tax credits which are generated each year by CAPEX,

[151] Order P-97-4(151) dated November 27, 2002, page 131.

> and which can be claimed up to 7 years after they are created. Thus, the actual tax paid is much less in the initial years than the tax actually paid on the tariff, and in the case of BPPL no taxes are paid initially.[152]

101. Tariffs are a function of both "costs" and the forecast volume. The TAPS Owners have also frequently misrepresented ANS production potential and compressed the expected economic life of TAPS and ANS. For example, the TSM assumes a 34.5-year life ending in 2011.**[153]** The effect of volumetric underestimates was to increase TAPS tariffs in the early years to improve the Owners' cash flow. The integrated corporate value of this activity was much the same as the DR&R and accelerated depreciation expense discussed previously. The Owners' rationale is obvious. They seek higher tariffs, which as Mr. Coulson admitted,[154] transfer money to themselves The State and independent shippers lose money through the resulting higher TAPS' tariffs. The Owners happily have collected this secondary source of economic value while focusing on the main purpose, which is to monetize the value of their reserves through TAPS.[155]

102. In other filings the Owners sometimes tell a different story. As explained above, BP Prudhoe Bay Royalty Trust[156] filed its Form 10-K with the U.S. Securities and Exchange Commission for the Fiscal Year ended December 31, 2008. In that filing, BP Prudhoe Bay Royalty Trust stated, "it is estimated that royalty payments to the trust will continue through the year 2031. BP Alaska expects continued economic production from the

[152] Telegram from BP Alaska Inc. to BP London, dated May 27, 1977.
[153] See RCA Order P-97-4(151) dated November 27, 2002, page 149.
[154] Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI; (December 8, 2010), page 55.
[155] Deposition Transcript of Charles J. Coulson in BP Pipelines (Alaska) Inc. et al vs. State of Alaska Department of Revenue et al, Case no 3AN-06-8446 CI; (December 8, 2010), page 58.
[156] The BP Prudhoe Bay Royalty Trust was created as a business trust in 1989. It holds a royalty interest of 16.4246% on the lesser of (1) the first 90,000 barrels of the average daily net production of crude oil and condensate from BP Alaska's working interest as of February 28, 1989 in the Prudhoe Bay oil field, or (2) the average actual daily net production of crude oil and condensate per quarter from BP Alaska's working interest. See BP Prudhoe Bay Royalty Trust, Form 10-K for the Fiscal Year ended December 31, 2008, page 2.

Prudhoe Bay field at a declining rate through 2075."[157] This is a more reasonable estimate of TAPS' economic-life, when the DOE/NETL review of other fields in northern Alaska is considered along with rising world crude price trends, than the 2045 date the SARB used for 2010 Assessment of TAPS. Nothing is certain. Nevertheless, there are other major probable and potential petroleum resources in the northern part of Alaska. Without TAPS, these would effectively be locked in.

103. Regardless of the amount of any additional volumes, the indisputable upward trend in the price of crude oil will affect TAPS' value and extend its economic life. TAPS will continue to be owned and operated for many more decades. The goal is simple: the Owners will monetize every last barrel they find in Prudhoe Bay and elsewhere in the north. The only constraint is the net-back to the wellhead needs to exceed the out-of-pocket costs of production. No one thinks this is a binding constraint anytime soon. This is particularly the case if the Owners use their actual marginal costs, not what they may disclose to others.

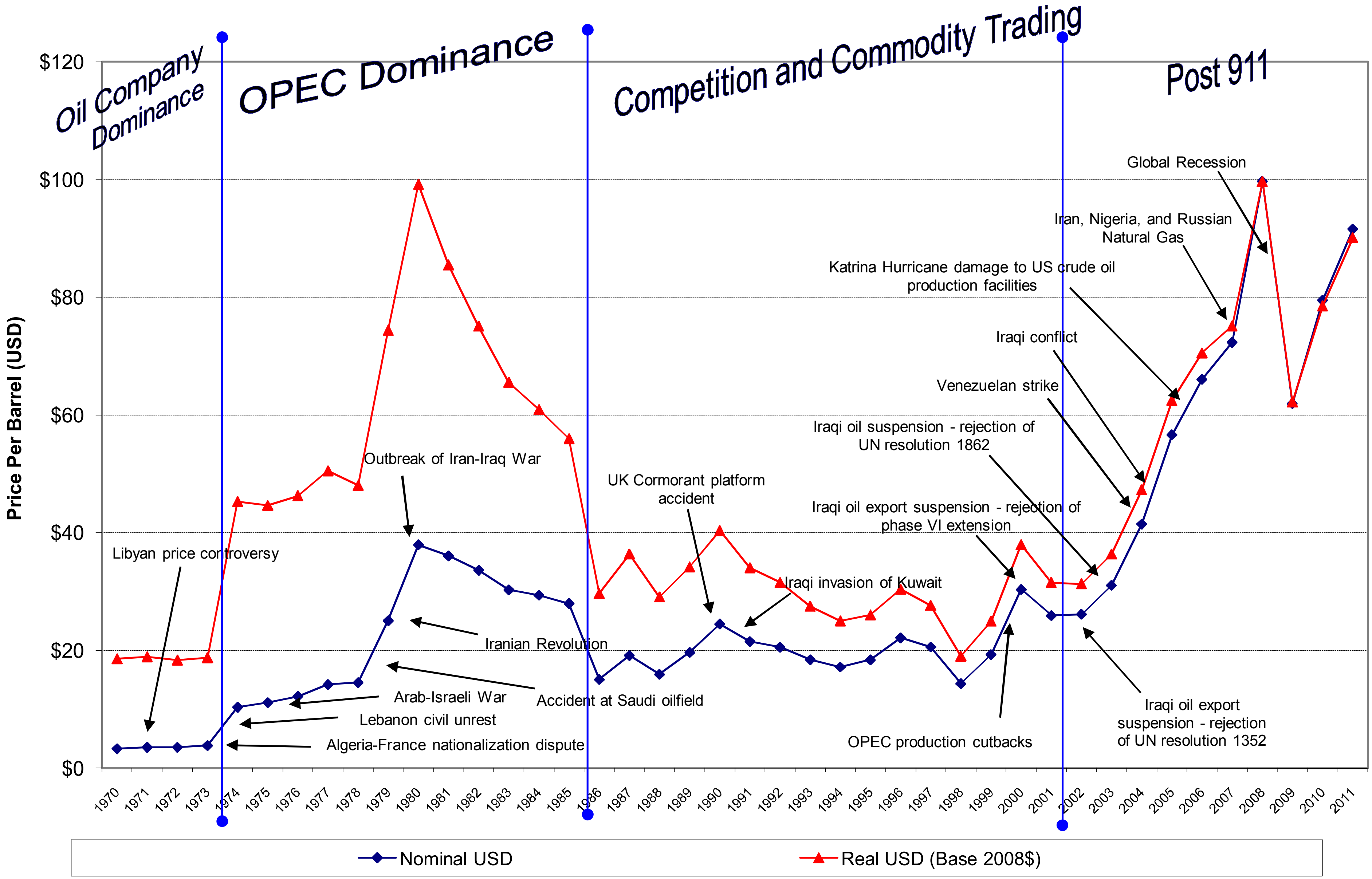
V. CONCLUSIONS

104. There are two relatively concise conclusions that I reach. First, TAPS is not a stand-alone pipeline and cannot be valued as such. It is part of a larger integrated Alaska petroleum operation. The value of TAPS is tied to the value of the product shipped. There is, in my mind, little chance of economic obsolescence for or abandonment of TAPS given three factors: (1) The worlds' appetite for crude oil is growing, particularly with strong signs of economic recovery; (2) Rising crude oil prices, albeit not without volatility, are the definitive trend that virtually all forecasters expect; and (3) There are

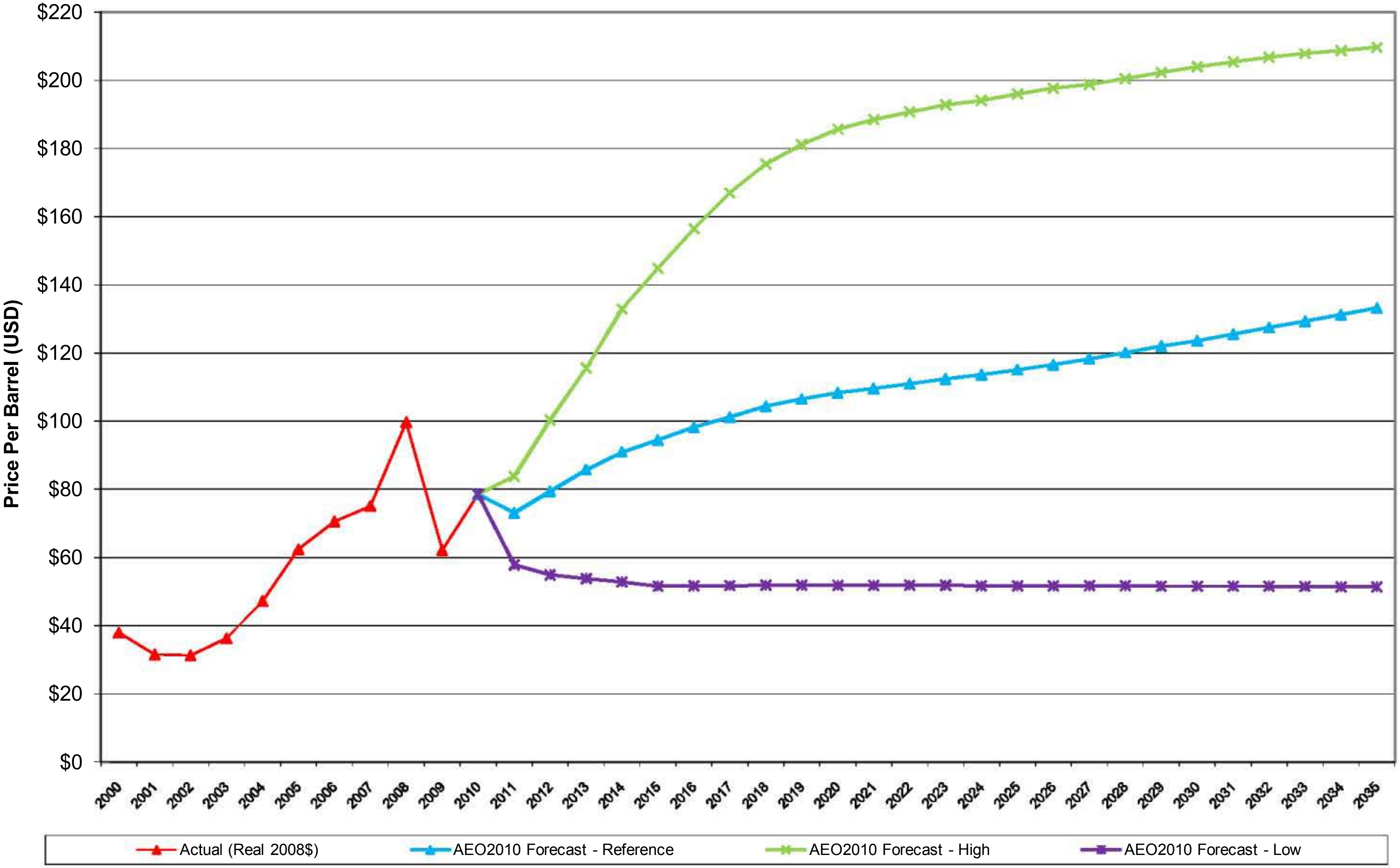
[157] BP Prudhoe Bay Royalty Trust, Form 10-K for the Fiscal Year ended December 31, 2007, page 18.

also reasonable, although not certain in every sense, reserve estimates that exceed the cumulative North Slope shipments on TAPS to-date. Second, the Owners' preference for tying the value of TAPS to tariff income vastly understates the actual value in use for the true Owners, the same corporations that own the upstream reserves, infrastructure, and production.

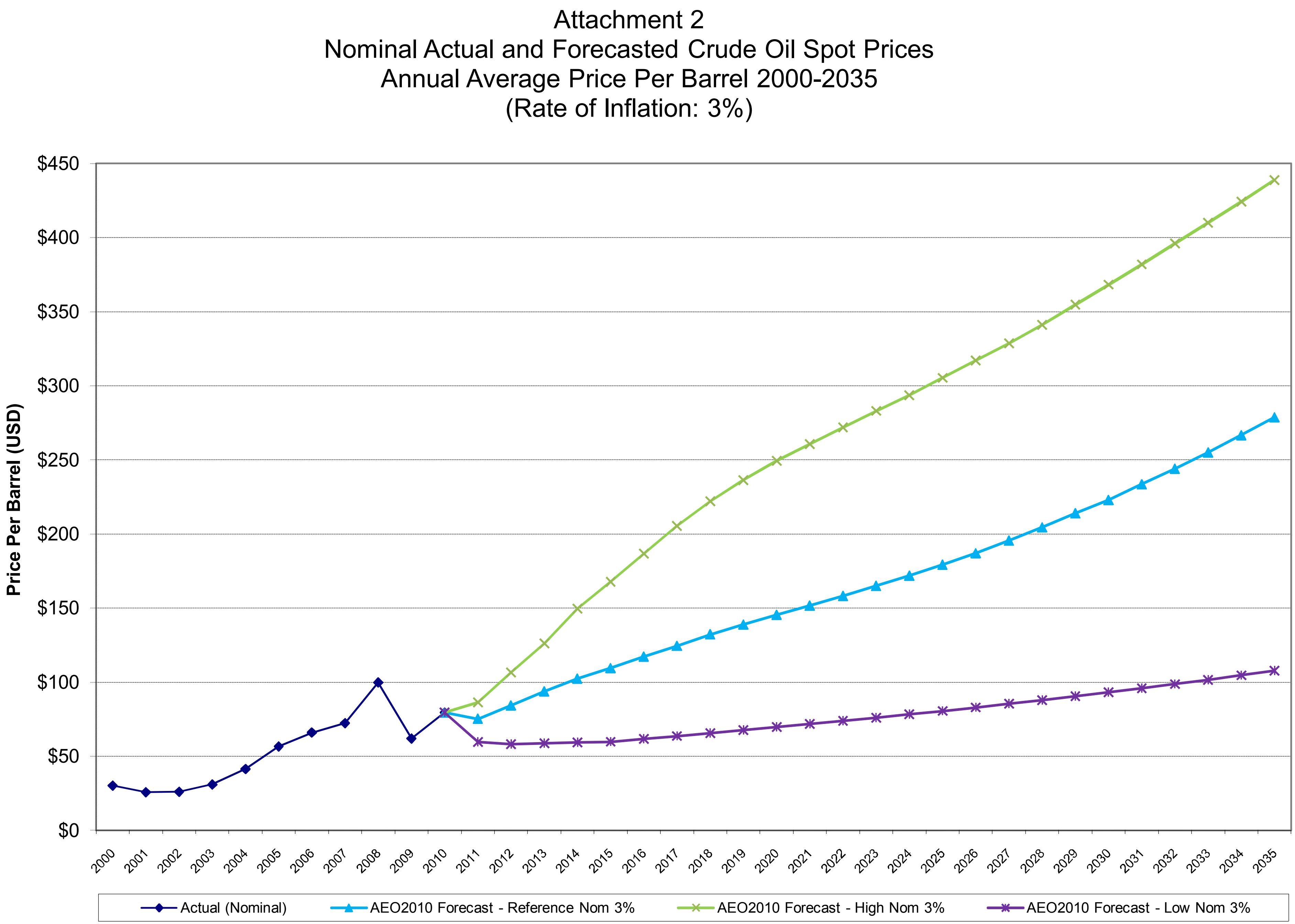
Attachment 1
West Texas Intermediate Crude Oil Spot Prices
Annual Average Price Per Barrel 1970–2011
(Base Year for Real Dollars: 2008)



Attachment 2
Real Actual and Forecasted Crude Oil Spot Prices
Annual Average Price Per Barrel 2000-2035
(2008$)



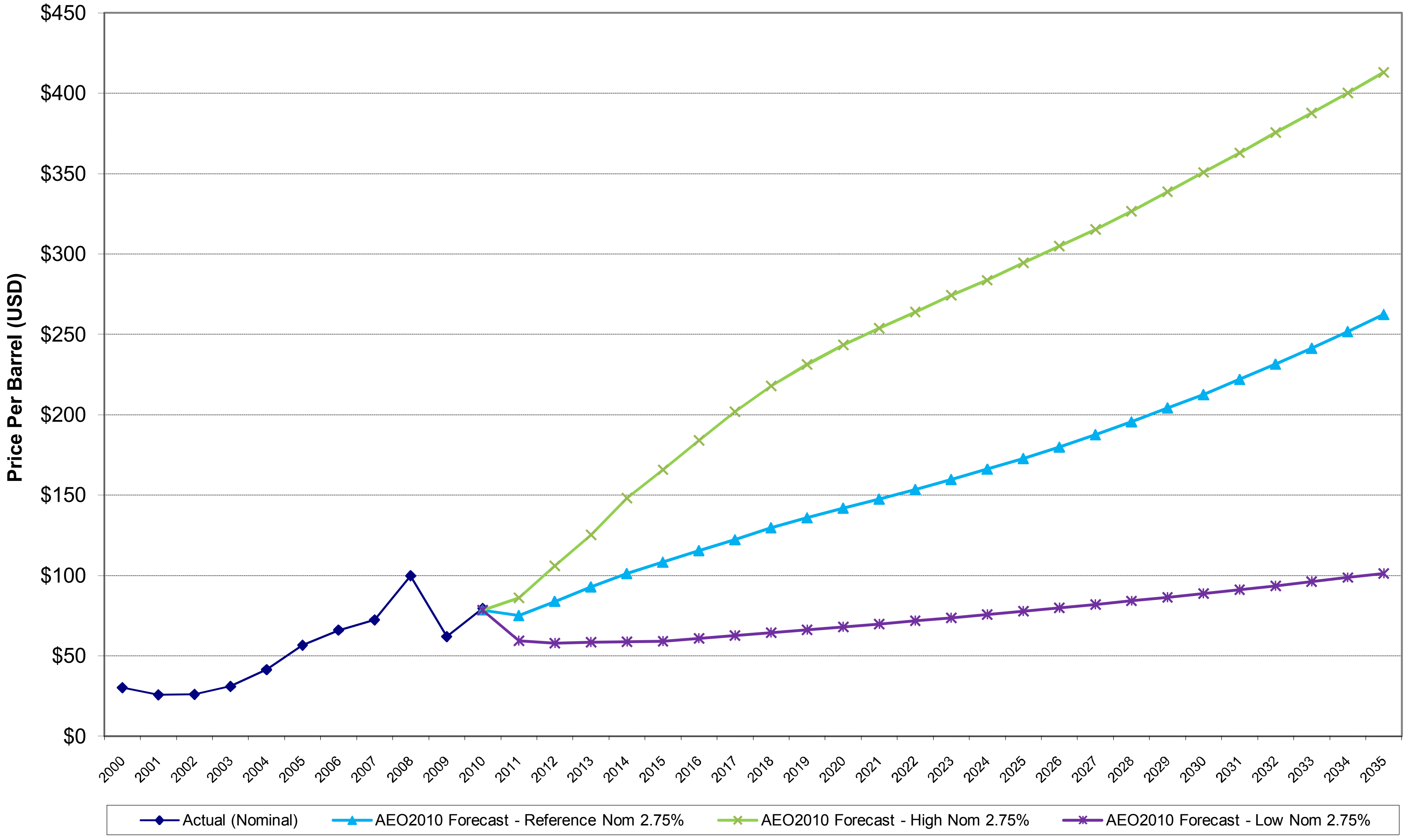
Note: Forecasts are for prices of imported low sulfur light crude oil



Note: Forecasts are for prices of imported low sulfur light crude oil

Cicchetti Report 000117

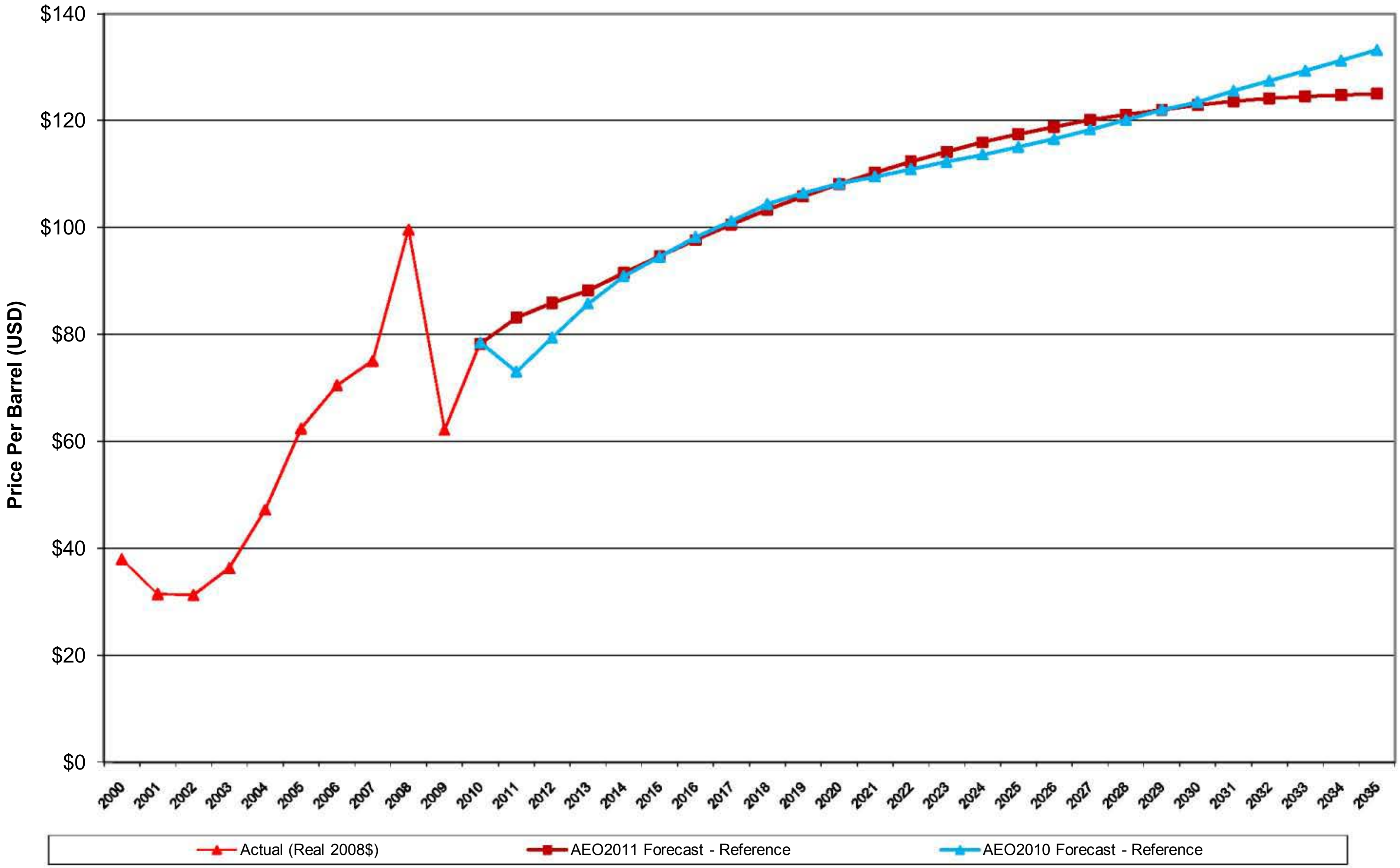
Attachment 2
Nominal Actual and Forecasted Crude Oil Spot Prices
Annual Average Price Per Barrel 2000-2035
(Rate of Inflation: 2.75%)



Note: Forecasts are for prices of imported low sulfur light crude oil

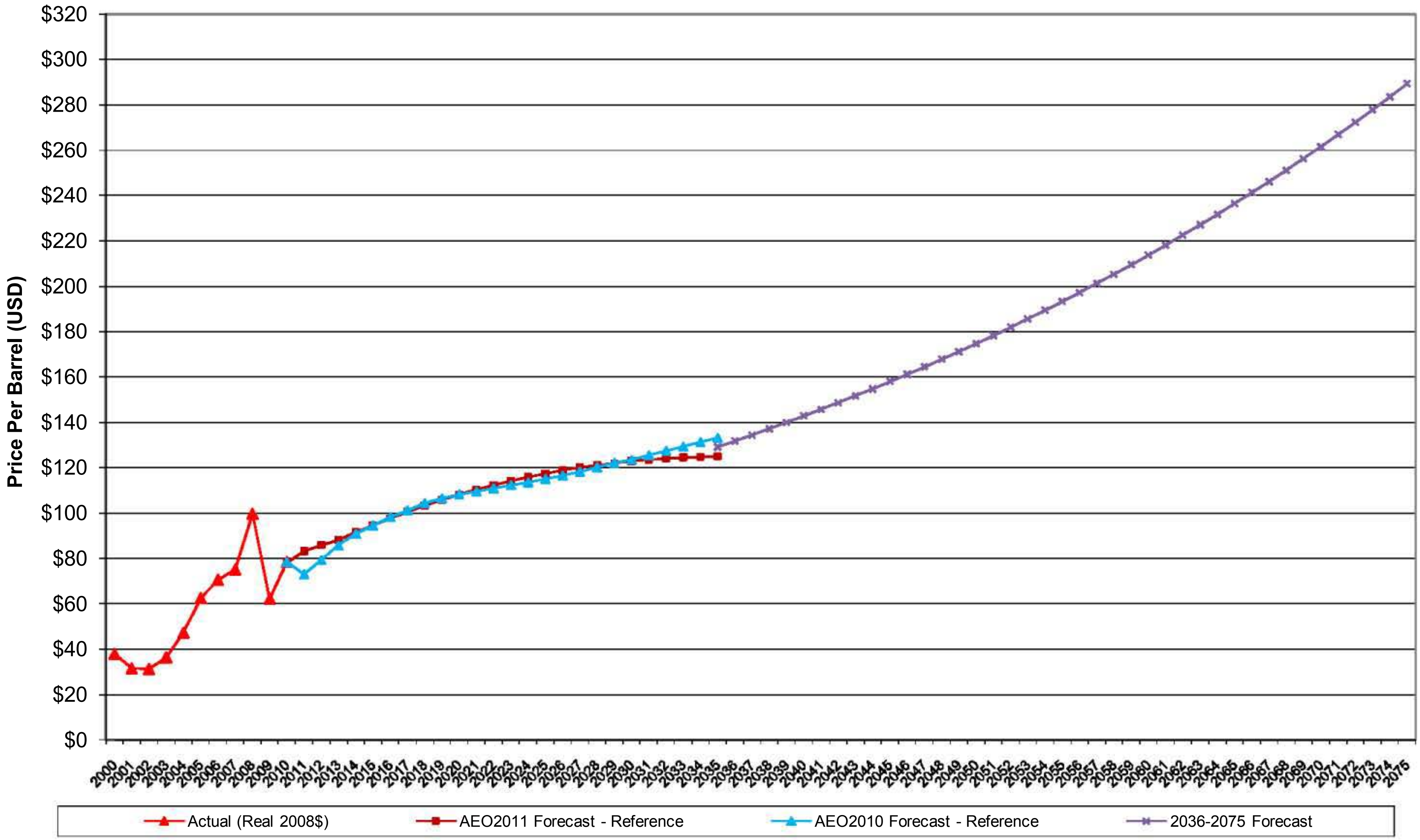
Cicchetti Report 000118

Attachment 3
Real Actual and Forecasted Crude Oil Spot Prices
Annual Average Price Per Barrel 2000-2035
(Comparison of 2011 and 2010 AEO Forecasts)



Note: Forecasts are for prices of imported low sulfur light crude oil
Note: 2011 AEO forecasts are in 2009$, 2010 AEO forecasts are in 2008$

Attachment 3
Real Actual and Forecasted Crude Oil Spot Prices
Annual Average Price Per Barrel 2000-2075
(Comparison of 2011 and 2010 AEO Forecasts)



Note: Forecasts are for prices of imported low sulfur light crude oil
Note: 2011 AEO forecasts are in 2009$, 2010 AEO forecasts are in 2008$
Note: 2036-2075 forecasts are based on the 2035 price and the annual growth rate in 2011-2035.

Attachment 4
Plot of Reserve Life and WTI Price
80
70
60
50
40
30
20
10
0
Life of Reserve (Years)
$0
$20
$40
$60
$80
$100
$120
WTI Price ($/bbl)

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2008-present	Senior Advisor to Navigant Consulting, Inc.;
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1998-2006	Jeffrey J. Miller Professor in Government, Business, and the Economy, University of Southern California;
1992-1996	Managing Director, Arthur Andersen Economic Consulting;
1991-2008	Adjunct Professor, University of Southern California
1991-1992	Co-Chairman, Putnam, Hayes & Bartlett, Inc.;
1988-1991	Managing Director, Putnam, Hayes & Bartlett, Inc.;
1987-1990	Deputy Director, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University;
1984-1987	Senior Vice President, National Economic Research Associates;
1980-1984	Co-Founder and Partner, Madison Consulting Group;
1979-1986	Professor of Economics and Environmental Studies, University of Wisconsin-Madison;
1977-1979	Chairman, Public Service Commission of Wisconsin, Appointed by Governor Patrick J. Lucey (member until 1980);
1975-1976	Director, Wisconsin Energy Office and Special Energy Counselor for Governor Patrick J. Lucey, State of Wisconsin;
1974-1979	Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972-1974	Visiting Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972	Associate Lecturer, School of Natural Resources of the University of Michigan;
1969-1972	Resources for the Future, Washington, D.C.;
1969	Post Doctoral Research: Ph.D., Economics, Rutgers University;
1968-1969	Instructor, Rutgers University;
1965	B.A., Economics, Colorado College;
1961-1964	Attended United States Air Force Academy.

ADVISORY BOARDS

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Alliance for Energy Security; Former Member;

Association of Environmental and Resource Economics, Former Executive Committee, Former Member;

California ISO Market Advisory Group –Former Member appointed by Governor Gray Davis;

Center for Public Policy Advisory Committee, Former Member;
Department of Energy, Fuel Oil Marketing Advisory Committee, Former Member;
Graduate School of Public Policy at the University of California, Berkeley; Former Board Member;
National Association of Regulatory Utility Commissioners, Executive Committee and Chairman of the Ad Hoc Committee on the National Energy Act, Former Member;
Public Interest Economics Center, Board of Directors, Former Member;
Rutgers University, Energy Research Advisory Board;
U.S. Chamber of Commerce Energy and Natural Resources Committee, Former Member.

EDITORIAL BOARDS

Journal of Environmental Economics and Management, Former Member
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Land Economics, Former Editor.

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