Alaska North Slope Oil Production and Revenue Projections

How much oil is produced on the North Slope in the coming years will greatly affect Alaska's economy and state revenues. In this Review, the author analyzes how future oil production and revenues from known North Slope fields could be affected by market prices and certain federal and state policies. He then projects the probable range of North Slope production and revenues to the year 2000, based on the likely range of oil prices and other factors. His major findings are:

- Despite the contribution of these new fields, onshore production will probably decline 60 to 70 percent by the year 2000. This decline will occur because production from the new, smaller fields will not come close to replacing current production from Prudhoe Bay.

- The cumulative total of oil produced in Alaska by the year 2010 could vary by several billion barrels, depending on the future price of oil. If oil prices maintain current levels, cumulative production from known fields on the North Slope will probably reach nearly 12 billion barrels by 2010. On the other hand, if prices fall to mid-1970s levels, cumulative North Slope production could be reduced to less than 10 billion barrels.

INTRODUCTION

Industry sources estimate total oil in place in the vicinity of the Prudhoe Bay field on Alaska's North Slope to be about 60 billion barrels. As shown on the Figure 1 map, this total includes 23 billion barrels of original oil in place at Prudhoe Bay, 5.5 billion in the Kuparuk River field, and 3 billion in the Lisburne formation underlying the Prudhoe Bay field. In addition, estimates of oil in place in the West Sak and Ugnu heavy oil zones overlying the Kuparuk River field range between 21 and 36 billion barrels. Known oil resources on the North Slope outside the immediate vicinity of Prudhoe Bay may bring the total oil in place in the region to 80 billion barrels.¹

However, industry can economically recover only a fraction of this original oil in place. This fraction is often called “recoverable reserves.” Under

¹Atlantic Richfield Company, as reported in Oil and Gas Journal, June 25, 1984, p. 56, and Arlon Tussing, personal communication, May 20, 1984.
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Institute Editor: Ronald Crowe
Editorial Assistant: Kandy Lee
907-278-4621

Main Institute Office:
707 "A" St., Suite 206
Anchorage, Alaska 99501

FEATURE

Matthew Berman
Alaska North Slope Oil Production and Revenue Projections

Matthew Berman is an assistant professor of economics with the Institute of Social and Economic Research in Anchorage.

economic conditions prevailing during the mid-1970s, only around 9 billion barrels of oil at Prudhoe Bay (and possibly some limited production from the Kuparuk River field) could be considered recoverable reserves. Still, the expected profitability of the gigantic Prudhoe Bay field was sufficient to finance the investment in the Trans-Alaska Pipeline System (TAPS) and the basic infrastructure on the North Slope without considering any potential production outside of the Sadlerochit Reservoir at Prudhoe.

The dramatic surge of world oil prices in 1979-1981 (and the subsequent decline) completely changed the outlook for profitable development of non-Prudhoe production on the North Slope. Although some development of those fields is already underway, future economic conditions may still affect decisions to develop most of this potential production. While we do not know precisely what oil prices will be in the coming years, we do believe that there is a range of likely world market prices. We use three scenarios that bracket the likely price range to provide alternative projections of future production and revenues.

We also consider the potential effects on future North Slope petroleum production and revenues of certain policies which may affect the feasibility of production from marginal fields. We focus on the effects of federal policy toward the oil and gas industry in Alaska and nationwide, but consider possible state initiatives as well. Policies considered include (1) permitting export of North Slope oil, (2) modifying Alaska severance and income taxes, and (3) extending the federal Windfall Profits Tax and eliminating the exemption for certain Alaska production.

SCOPE

This Review focuses on the North Slope region because that is where the largest concentrations of oil occur in Alaska and where most of the state's oil will be produced in the next 15 years. Currently, over 95 percent of Alaska's oil production takes place in the North Slope region, and its predominance is likely to continue for the foreseeable future. Oil production in the Cook Inlet region—the only other producing province—has been declining steadily and is not a significant factor in state revenue projections.2

This analysis concentrates on potential produc-

2Alaska Department of Revenue projections assume an average production decline rate of 12 percent per year. Total oil and gas royalties and severance tax collections would decline to 2 percent of total state royalty and severance taxes by 1990. See Petroleum Production Revenue Forecast, quarterly report, March 1984, Alaska Department of Revenue, Petroleum Revenue Division, p. 16, 18.
tion from known fields on the North Slope up to around the year 2000. It is likely that additional large oil reservoirs will be discovered in the region by the end of the century. The most promising unexplored areas within state jurisdiction are either offshore or within the boundaries of the Arctic National Wildlife Refuge. Exploration is just beginning in the wildlife refuge, and adjacent offshore areas have not yet been leased. While large discoveries may result from exploration in these areas, the lengthy permitting process and the high cost of access will most likely defer production beyond the year 2000.

Market prices and public policy will affect the location and intensity of industry exploration effort, timing of discoveries, and commencement of production. However, major impacts on future production resulting from an altered rate of discovery of new fields would also have little effect on future production until after the turn of the century. Since our focus is on Alaska petroleum production and revenues to the year 2000, we do not attempt to quantify this potential effect.

Instead, we analyze how market prices and government policies may affect the feasibility of investments to develop and operate major North Slope fields that have already been discovered. We project annual Alaska petroleum production and revenues to 2000, as well as implied cumulative production and revenues from the currently known North Slope fields to 2010.

While commercial discoveries and subsequent production are likely to occur on the Alaska Outer Continental Shelf (OCS), we do not have sufficient information to analyze the effects of prices and policies on OCS production until oil is discovered there. Under current federal policy, the state will receive no direct revenues from OCS production.3

We ignore the potential role of natural gas in the production and revenue scenarios analyzed below, assuming that the region's vast quantities of natural gas will continue to be useful only to support oil production-related activities. If a transportation system is ever built to market Alaska North Slope gas, the high cost would virtually assure that the wellhead price, and hence the direct state petroleum revenues, would be inconsequential. Natural gas discoveries from federal leases in the Bering Sea would likewise be uneconomical to produce under reasonable cost and world market price scenarios.4

**PRODUCTION AND REVENUES FROM KNOWN NORTH SLOPE FIELDS**

The objective of this study was to analyze how Alaska petroleum production and revenues are likely to respond to certain specific assumptions about market prices and federal policy. This required an analysis of the potential economic feasibility of producing oil from known North Slope fields under a number of assumptions about size of reserves and cost of production, as well as price and policy factors.

Thus, our comparative projections involved a two-step approach. First, we determined if development of a known but undeveloped field would be economically viable under the set of assumptions associated with the particular scenario. We assumed development of a field was feasible if the anticipated discounted cash flow exceeded a 10-percent return on investment above inflation (see Assumptions, page 4). We then added production and revenues from fields calculated to have positive development values to derive the total regional projections.

We projected North Slope production and revenues under eight different scenarios. First, we considered three alternative scenarios for market prices of North Slope oil. Next we examined three scenarios relating federal policy to wellhead oil prices. Finally, we analyzed the effects of two hypothetical modifications to the state's petroleum tax structure.

The eight scenarios chosen cover only a small fraction of the potential variations in market and policy factors affecting Alaska North Slope production and revenues over the next several decades. Nevertheless, we believe that they represent the range of reasonable opportunities and expectations.

**Sensitivity of Production to Wellhead Prices**

**Market Price Scenarios:** The purpose of these scenarios is to project likely production rates based on economic feasibility of currently undeveloped North Slope oil fields under low-, moderate-, and high-price assumptions that bracket the likely range of outcomes. We do not attempt to estimate the sensitivity of production to small changes in the wellhead price, since sufficient information is not available to make an accurate assessment. The market price cases assume no change in current federal and state tax structures. (Continued on page 5.)

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NORTH SLOPE PETROLEUM DEVELOPMENT ASSUMPTIONS

North Slope Fields Considered

We derived production scenarios for the North Slope region from actual and hypothetical development patterns for nine fields or development zones. These included the currently producing Prudhoe and Kuparuk fields as well as seven fields in various stages of feasibility study by industry. We explicitly considered multiple options for development of four of the nine fields, assuming optimistically that any technological problems encountered would be overcome.

Our assumptions for development patterns of new fields were broadly consistent with assumptions used by the Alaska Department of Revenue for forecasting state petroleum revenues. Unlike the department in its forecasts, we explicitly considered changes in the level of oil production which might be economically feasible under different market prices and public policies. Our production and revenue projections also differ in some minor details and refer to the calendar year, rather than the fiscal year. A brief description of potential development patterns considered for each of the fields is as follows: a

Prudhoe Bay: We assumed an average production rate of 1.534 million barrels per day (BPD) from Prudhoe through 1987. In the basic projection, production would decline to 1.054 million BPD in 1990, and to just over 800 thousand BPD in 2000. If the miscible-gas, enhanced-oil recovery project proves feasible, production would decline somewhat more slowly with a cumulative increase in recovery of almost 115 million barrels.

Kuparuk: We considered development of the field in two discrete stages. Stage 1 describes the currently producing area while Stage 2 refers to the target of ongoing construction of development facilities for the Kuparuk River producing zone. If both stages of the Kuparuk field prove feasible, potential recoverable reserves would just exceed one billion barrels of oil. We assume peak production from each stage conservatively at around 110 thousand BPD, with production available from the second stage in 1985.

Lisburne: ARCO has been testing development wells in the Lisburne pool underlying the Prudhoe Bay field since 1982. We assumed recoverable reserves of around 450 million barrels if commercial development of this prospect is feasible, with production possible by 1987 and reaching 100 thousand BPD.

Milne Point: We examined two stages for development of the smaller Milne Point prospect. The first would target primarily the Kuparuk pay, which might begin producing in 1986, while the second stage would produce from the shallower West Sak pay, beginning in 1990. Peak production from each development stage would be around 30 thousand BPD, with recoverable reserves of about 100 million barrels from the combined project.

Endicott: If successfully developed, the Endicott River area might provide production of 85 thousand BPD, with a startup date in 1987. Although much larger amounts of oil are present in the vicinity, we assumed recoverable reserves of about 300 million barrels.

Gwydwr Bay: Production from this smaller North Slope field could start at 10 thousand BPD with reserves of around 30 million barrels. Production could start as early as 1987 if a decision is made soon to develop the field.

Flaxman: As much as 600 million barrels of oil may be recoverable in the Point Thompson-Flaxman Island area east of Prudhoe Bay. More than one-half of this amount, however, is more appropriately described as gas condensate in the giant Point Thompson gas field. We assumed that the gas field is not feasible to develop in any of the scenarios. However, we did consider development of less than 300 million barrels in a Flaxman field. Oil production, if feasible, might begin by 1990, with a peak flow rate of 80 thousand BPD.

Seal Island: Shell has recently confirmed a discovery in state and disputed state-federal waters in the Beaufort Sea, with two wells yielding 5,000 BPD of 40-degree gravity oil. If development is feasible, the new field could begin production by 1992, with cumulative recovery eventually exceeding 300 million barrels. We assumed a peak production rate of 85 thousand BPD and also assumed that the jurisdictional dispute would be resolved in favor of the State of Alaska. b

West Sak: We considered two alternative phases for potential large-scale commercial development of shallow Cretaceous heavy oil deposits near the Kuparuk producing area. Phase I covered the area immediately overlying the Kuparuk, with which some development facilities and costs could be shared. This phase might begin in 1989, recovering as much as 750 million barrels if production is economically viable, with peak production reaching 150 thousand BPD. The second phase essentially covered additional development of a resource four times as large, possibly beginning in 1992, with higher costs due to the need to construct additional development facilities.

aSee Alaska Department of Revenue, Petroleum Production Revenue Forecast, Quarterly Report, September 1984, pp. 13-16. A listing and documentation for the model used for the analysis presented in this Review, along with the exact production parameters and cost assumptions used for each of the nine potential fields may be found in Matthew Berman, et al., Alaska Petroleum Revenues: the Influence of Federal Policy, ISER, October 1984, Appendix F.

bSee Oil and Gas Journal, July 2, 1984, p. 27.
Low Price (Scenario 1): The low-price scenario assumes a constant real market price schedule of $10 per barrel for Prudhoe Bay oil, or $7.50 per barrel less than that currently prevailing on the North Slope. This price corresponds roughly to a world price of $20 per barrel, which might result from the collapse of OPEC. The wellhead price of $10 per barrel in 1984 dollars is roughly comparable, after adjusting for inflation, to the average price level prevailing during the initial 2 to 3 years of operation of the Trans-Alaska Pipeline. Thus, the low-price scenario projects feasible North Slope oil production at the real wellhead price level prevailing in the mid-1970s.

At the wellhead price levels prevailing in the 1970s, only Prudhoe Bay production (without the miscible-gas enhanced oil recovery project) can cover fixed development costs. Although development of the Kuparuk field is not profitable in the low case under the current industry tax structure, our estimates show that some Kuparuk development would be feasible under the lower state tax rates prevailing during the mid-1970s, even with the low market prices.

If oil prices fell back to the mid-1970s level, all major new North Slope investments would lose money, including the ongoing expansion of Kuparuk production. We assumed that current production rates at Kuparuk would continue in any case, since the major fixed costs have already been incurred there. Although producers might complete the current Kuparuk expansion as well, even with the low price projection, they would probably abandon all other North Slope development projects. Thus, the low-price case also represents a lower bound for likely North Slope oil production even if world oil prices collapse.

Figure 2 shows projected Alaska North Slope production under the low-price assumption. Total projected oil production in the low-price case begins falling in 1987 from its approximate current rate of 1.6 million barrels per day (BPD). Production declines to 1.1 million barrels in 1990 and to 300 thousand BPD in 2000.

Moderate Price (Scenario 2): For the moderate-price scenario, we assumed that wellhead oil prices would remain constant (after adjusting for inflation) at about the current levels throughout the projection period. The moderate price projected for Prudhoe Bay was $17.50 in 1984 dollars and $16.00 for Kuparuk. This is a conservative price projection, due in part to the likely decline over time in the TAPS tariff, at least in today’s dollars. Thus, we might think of the moderate price projection as a risk-adjusted, middle-range scenario. It is roughly consistent with the Alaska Department of Revenue’s long-run wellhead price projections.

The moderate-case scenario represents additional projected oil production made possible by the net rise in real wellhead oil prices to the mid-1984 level, assuming that the net price rise is permanent. Figure 3 projects incremental North Slope oil production under the moderate (1984 real price) assumptions above what was feasible under the low (1970s) price level. The figure shows production from four new fields—Milne Point, Endicott, Lisburne, and Seal Island—as well as additional production from Prudhoe Bay and Kuparuk. Production for three of the fields—Gwydyr Bay, Flaxman, and West Sak—still appears infeasible under the moderate-price assumptions.

The figure shows incremental production, resulting from the net rise in world oil prices from the mid-1970s to 1984, peaking at over 360 thousand BPD in 1988. Incremental production would then decline to around 280 thousand BPD in 1995 and to around 160 thousand BPD in 2000. Although production would be declining by 2000 in all fields, two of the fields, Prudhoe Bay and Seal Island, would still be producing in 2010, according to the projections.

**High Price (Scenario 3):** The high-price scenario assumes a constant real price of $7.50 per barrel greater than the current price, or $25 for Prudhoe Bay oil. This is roughly the same real price as prevailed in 1981 at the historical peak of world oil prices. This scenario projects oil production that would be feasible if real wellhead oil prices were to return permanently to 1981 levels.

Figure 4 projects incremental production above the low-price case for the high-price scenario. In the high case, all the fields would be feasible except for Gwydyr Bay, which would be nearly feasible. While it is possible that this smaller field could be developed in conjunction with adjacent, more profitable fields, costs are apparently too high for it to stand on its own under even an optimistic price projection.

Incremental North Slope production feasible at the 1981 real wellhead oil price level (beyond that which was feasible at the 1970s price level) would rise to over 1.1 million BPD in 1993-1995. This figure includes about 300 thousand BPD from the “marginal fields” (fields which would be feasible in the moderate case but not in the low case), as well as 800 thousand BPD from the Flaxman and West Sak developments. Incremental production in the high-price scenario would decline slowly, still exceeding 900 thousand BPD by 2000.

**Federal Wellhead Price Policy (Scenario 4):** A policy of major discriminatory federal action against Alaska petroleum producers and the state prevents export of oil carried through the Trans-Alaska Pipeline. The economic effect on Alaska petroleum production of lifting the current restriction is unclear at this point since it is not certain how producers and the state would choose to react to the foreign market opportunities, if they were available. It is most likely that a large portion of North Slope oil would continue to supply domestic markets. We assume for the sake of the scenario that the opportunity to export North Slope oil would lead to an increase in the average wellhead price of $2.50 in 1984 dollars.\(^6\)

A separate area of federal policy that has a large potential effect on North Slope wellhead oil prices is the set of rules chosen by the Federal Energy Regulatory Commission (FERC) as the basis for determining the TAPS tariff. The state and the pipeline owners have been disputing the tariff rules continuously since the pipeline began operation in 1977. A final ruling by the agency along the lines of the proposed settlement submitted by ARCO in December 1984, might also raise the average wellhead price on the North Slope by $2.50 per barrel by the 1990s, similar to the export case assumption.

Figure 5 summarizes North Slope production for the hypothetical “export” case. Higher wellhead oil prices in this scenario, which might also arise from a favorable TAPS tariff ruling, would permit development of the first stage of West Sak heavy oil and the Flaxman field. These fields would provide 140 thousand BPD of additional production in 1995 and a little more than half that in 2000. Total projected production above that projected for the low (mid-1970s real wellhead) price scenario would peak at around 500 thousand BPD in 1993 and decline to 238 thousand BPD in 2000.

Direct wellhead price control is another area of federal petroleum industry policy that has in the past greatly concerned oil producers and producing states. Oil price controls are unlikely to reappear under current or weaker market conditions. Gas price controls are largely irrelevant to the North Slope region. Re-emergence of price controls would be possible under a scenario of renewed supply disruption.

\(^6\) A detailed analysis of a number of scenarios for the potential effects of lifting the export ban on the price received for North Slope oil is contained in "The Export of Oil to Japan—State Revenue Impacts," in Alaska Department of Revenue, Division of Petroleum Revenue, Petroleum Production and Revenue Forecast, quarterly report, March 1983, pp. 17-24.
More likely, however, Congress would add a new producer excise tax (or simply extend the life of the Windfall Profits Tax), as much for its revenue-raising potential as for its redistributive role. We consider the impact of such a hypothetical move below.

Analysis of price scenario results: Figure 6 summarizes the North Slope wellhead price assumptions for the four price scenarios, showing the relationship of projected to historical real price levels. Figure 7 summarizes total projected North Slope oil production rates for the four scenarios associated with the alternative projected wellhead price levels shown in Figure 6. Total oil production rates in the low-price case would begin falling from over 1.6 million BPD in 1987, dropping to 1.1 million BPD in 1990, and to 300 thousand BPD in 2000. The figure shows that annual production in the moderate price case would peak at 1.9 million BPD in 1987, then decline to around 1.1 million BPD in 1993, and further decline to approximately 500 thousand BPD in 2000.

Higher wellhead oil prices in the export scenario would permit development of the first stage of West Sak heavy oil and the Flaxman field. Total North Slope oil production shown in Figure 7 for the export case would remain above 600 thousand BPD until 2000. Total North Slope production in the high price case, which includes large-scale development of West Sak sands, would actually peak at over 1.9 million BPD in 1993, and still exceed 1.2 million BPD in 2000.

Table 1 shows the tabulation of cumulative projected production by field for the four wellhead-price scenarios discussed above. The table also includes for comparison a set of projections for North Slope oil production made in 1981 by economist Arlon Tussing. Cumulative production to 2000 for all four of our scenarios is within the 95-percent confidence range of the former projections, with the Tussing “most-likely” scenario falling between the moderate and export-price scenarios of the current study. Our high-price and low-price projections, however, appear to narrow considerably the range of uncertainty of the earlier estimates regarding cumulative North Slope oil production that will be feasible in this century.

Figure 8 graphs the sensitivity of cumulative production from known North Slope fields to the wellhead price. This was done by interpolating results of the four scenario projections shown in Table 1. If

\[\text{Figure 5. Additional North Slope Oil Production} \]  
(Feasible at $20/BBL Wellhead Price)

\[\text{Figure 6. North Slope Wellhead Oil Prices} \]  
(Historical and Projected)

\[\text{Figure 7. North Slope Oil Production} \]  
(Feasible at Four Wellhead Prices)

\[\text{Table 1. Comparison of North Slope Production Projections} \]

Figure 8. Cumulative Projected North Slope Oil Production to 2010

Oil prices maintain current levels, cumulative production from known fields on the North Slope will probably reach nearly 12 billion barrels by 2010.\(^8\) If the price rose to $20 per barrel (in 1984 dollars), cumulative production by 2010 might exceed 16 billion barrels. On the other hand, if producers expected wellhead prices to fall to $10 per barrel (again in 1984 dollars), cumulative production might not reach 10 billion barrels.

### Price Sensitivity of Revenues

In this section we analyze the sensitivity of expected future revenues to wellhead prices. The revenue patterns include the effects of changes in the quantity of oil which is feasible to produce as a result of price changes, as well as the effects of changes in unit wellhead revenues.

Figure 9 illustrates the projected pattern of Alaska state petroleum revenues received from North Slope oil production under the four different scenarii for the wellhead price of oil. Total state petroleum revenues in Figure 9 include oil royalties, oil severance and conservation taxes, petroleum property taxes on production property, and Alaska corporate

\(^8\)Assuming original oil in place of 60 billion barrels, this implies a cumulative recovery rate of 20 percent. This rate is somewhat lower than industry averages, due to the large fraction of heavy oil (which is more difficult economically to extract) and the high-cost environment on Alaska’s North Slope.

<table>
<thead>
<tr>
<th>Field or scenario</th>
<th>To 2000</th>
<th>To 2010</th>
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</thead>
<tbody>
<tr>
<td>Low Case</td>
<td>9.25</td>
<td>9.85</td>
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<tr>
<td>Prudhoe Bay</td>
<td>8.83</td>
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<td>Kuparuk</td>
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<td>0.43</td>
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<tr>
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<tr>
<td>Prudhoe Bay</td>
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<td>Kuparuk</td>
<td>0.87</td>
<td>0.93</td>
</tr>
<tr>
<td>Milne Point</td>
<td>0.10</td>
<td>0.10</td>
</tr>
<tr>
<td>Lisburne</td>
<td>0.37</td>
<td>0.38</td>
</tr>
<tr>
<td>Endicott</td>
<td>0.27</td>
<td>0.31</td>
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<tr>
<td>Seal Island</td>
<td>0.22</td>
<td>0.30</td>
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<tr>
<td>Flaxman</td>
<td>0.20</td>
<td>0.26</td>
</tr>
<tr>
<td>West Sak</td>
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<td>0.81</td>
</tr>
<tr>
<td>Export Case</td>
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<td>12.63</td>
</tr>
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<td>Kuparuk</td>
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<td>West Sak</td>
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<td>High Case</td>
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<td>0.26</td>
</tr>
<tr>
<td>West Sak</td>
<td>2.47</td>
<td>4.55</td>
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</tbody>
</table>

\(^{\text{High Case}}\)

Tussing (1981)\(^{\text{b}}\)

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<tr>
<td>95 percent</td>
<td>8.51</td>
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<tr>
<td>Most Likely</td>
<td>11.24</td>
</tr>
<tr>
<td>5 percent</td>
<td>22.62</td>
</tr>
</tbody>
</table>

Note: Individual field projections may not add to scenario totals due to rounding.

\(^{\text{a}}\)Includes production through 1983 of 3.23 billion barrels from Prudhoe Bay and 0.07 billion barrels from Kuparuk.

income taxes (apportioned share), but do not include the minor amount of revenues derived from gas production.

Projected state revenues in the moderate price case would average around $3 billion in 1984 dollars until 1989, then decline to $2 billion in 1992 and to $730 million (all in 1984 dollars) in 2000. Real state petroleum revenues in the low-price case would decline from a level of $1.6 billion per year to $1 billion in 1991, and to only $240 million in 2000. State revenues in the export case are 21 percent higher than in the moderate case in 1990 and 34 percent higher in 2000. Real state petroleum revenues in the high price case peak at $4.4 billion in 1987 (measured in 1984 dollars), but are still over $3 billion in 1995 and nearly $2 billion in 2000.

We projected that federal petroleum revenues (Windfall Profits Tax and corporate income tax) derived from developing these same North Slope fields would show a pattern which is remarkably similar to that projected for the state revenues. Although projected federal corporate income taxes would be lower initially due to deductions for major field development expenditures, the federal government would receive approximately the same total revenue from these fields as would the State of Alaska.

Figure 10 summarizes projected cumulative state and federal petroleum revenues under the different price scenarios over the period 1983-2010, in 1984 dollars, derived from development of known North Slope oil deposits. The figure shows clearly the high degree of uncertainty for Alaska petroleum revenues associated with uncertainty about the level of wellhead prices. Cumulative projected state petroleum revenues for 1983-2010 from the North Slope would amount to $40 billion (in 1984 dollars) if current wellhead prices continue, but may ultimately total between $20 and $70 billion dollars, depending on future wellhead oil price levels. Cumulative federal revenues are slightly more responsive to wellhead oil prices than are state revenues, due to the federal government's greater reliance on income taxes as opposed to excise taxes and royalties for collecting petroleum revenues.

**Effects of Revenue Policy on Production and State Revenues**

A number of proposals that attempt to set a federal severance tax policy on energy resources have surfaced recently in Congress. These include a proposed national severance tax on oil of around $3 per barrel and proposals to limit state severance taxes. A national severance tax of, say, $3 per barrel, if it were applied to state royalty shares as well as to private production, would affect Alaska production and state revenues in the same way as would a $3 reduction in the market price. One can infer from Figures 8 and 10 that the effect of such a new federal tax might be a reduction of around a billion barrels in recoverable North Slope reserves, and an accompanying loss.

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9The federal statute applies a tax rate schedule to the excess of the wellhead price over a “base price” representing a 1979 wellhead price level. See PL 96-223, 94 Stat. 229 (1980); 26 USC §§ 4986-4998.
by 2010 of around $10 billion (in 1984 dollars) in state revenues.

Federal Windfall Profits Tax Extension (Scenarios 5 and 6): Congress passed the federal Windfall Profits Tax in 1980 as part of the program removing controls from domestic oil prices. It is an excise tax on oil production with a rate structure based on the difference between current oil prices and 1979 levels—the so-called “windfall profit” from decontrol—and with a provision that causes the tax to expire automatically after about 10 years. Attempts to prolong the life of the Windfall Profits Tax, or even increase its effective rates, are more likely to succeed in Congress than attempts to impose a new federal tax. North Slope prices in the low and moderate cases would be low enough so that the Windfall Profits Tax would have a very limited impact. We considered two scenarios, however, in which Congress would not only extend the Windfall Profits Tax indefinitely, but also would eliminate the current special tax exemption for non-Prudhoe North Slope oil. One scenario combines the extended Windfall Profits Tax with the high-price scenario, the other with the export scenario.

Our accounting projections showed that extending the Windfall Profits Tax and removing the Alaska exemptions would not change the economic feasibility of any proposed North Slope development project. Indeed, even in the high-price scenario, only Prudhoe Bay would feel the impact of the tax. This is because the statute classifies production from all other North Slope fields as “newly discovered oil.” By statute, the “base price” for this type of oil increases 2 percent per year above inflation. Even with a $7.50 increase in world oil prices, the North Slope price typically would not exceed the statutory base price.

However, an extended Windfall Profits Tax would have a significant impact on federal revenues from the Prudhoe Bay field. The tax would raise nearly $500 million (measured in 1984 dollars) in additional federal revenues from Prudhoe Bay in 1995 in the high case, and nearly $300 million more in 2000. State revenues would decline by $20- to $80-million annually in the 1990s, due to the effect of higher Windfall Profits Tax deductions from state taxable income. In the export case, federal revenues would increase by around $170 million in 1995 and by nearly $100 million in 2000 if Congress were to retain the Windfall Profits Tax through the end of the century.

State Tax Policy (Scenarios 7 and 8): Scenarios associated with modifications of the Alaska petroleum tax structure would involve potential changes in economic feasibility of marginal fields which are more subtle and complex. We consider projections associated with two such scenarios. We assume the moderate wellhead price projection would prevail in both scenarios because it is more representative of likely future market conditions.

Both scenarios allow us to examine the effects of hypothetical reductions of the Alaska severance tax rate to 10 percent from the current 12.25- to 15-percent schedule. In one scenario, the legislature would eliminate the economic limit factor (ELF)—a formula which reduces the effective tax rate as average production rates per well decline—so that the effective rate would remain at 10 percent.11

In the other scenario, the state would win court approval and reinstate the separate accounting method of assessing petroleum corporate income taxes. The separate accounting method assesses the Alaska corporate income tax rate of 9.4 percent on income earned within the state from oil and gas production and transportation activities. The tax was repealed in 1981 under pressure of litigation. This scenario assumes that the severance tax structure would stay intact, except for a reduction in the nominal rate to 10 percent.

The projections for the two state tax scenarios—both based on the assumption of moderate price levels—are remarkably different. In the scenario that eliminates the ELF, we projected that cumulative state revenues to 2010 would be 18 percent lower than with the current tax structure, even though the wellhead price assumptions are the same. Revenues would be lower partly because production in this case would be only 92 percent of moderate case production in 1990, and 95 percent of moderate case production in 2000. The Endicott field and the Milne Point field do not appear to be feasible to develop...

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10James Love, in “Evaluation of Proposed Federal Energy Taxes,” Alaska Department of Revenue, July 7, 1982, discussed several alternative proposed national energy taxes and their hypothetical impacts on the State of Alaska. Love also illustrated the minimal impact of the federal Windfall Profits Tax on North Slope oil under prevailing market prices, even if the exemption were removed for non-Prudhoe oil.

11See Alaska Statutes, 43.55. The exact formula for the economic limit factor for oil production equals:

\[(1 - \frac{PEL}{TP}) \exp(460 \times WD/PEL)\]

where: PEL = monthly production rate at the economic limit; TP = total production during the month for which the tax is to be paid; WD = total number of well days for which the tax is to be paid; and

“exp” indicates that the expression following is an exponent.

The economic limit factor (ELF) for gas production equals:

\[1 - \frac{PEL}{TP}.\]
without the ELF. Apparently, the ELF provision reduces the effective severance tax rates projected for the marginal North Slope fields significantly below 10 percent, despite the apparent high nominal rates of the current tax structure. Thus, eliminating the ELF provides an example of an attempt to increase revenues which results in lower revenues.

The scenario in which the state modifies the corporate income tax to recapture revenue lost from reducing the severance tax rate to 10 percent provides no change in projected production from the moderate case. Total state revenues in this case would be only 1 percent lower than the moderate case projection in 1990 and would actually be 6 percent higher in 2000. Clearly, reinstating the separate accounting method for assessing petroleum corporate income taxes (if a court decision favors its constitutionality) would be a better option for protecting state revenue while encouraging production from marginal fields than turning the severance tax into a true flat-rate tax.

State Policy Toward the Marginal Fields

We have analyzed two possible modifications of Alaska’s petroleum tax structure which included reducing nominal oil severance tax rates to 10 percent. One alternative would eliminate the economic limit factor (ELF) (which reduces effective severance tax rates for less-productive fields) to make the Alaska severance tax a true flat-rate tax. The other alternative would retain the ELF but reinstate the separate accounting method for the petroleum corporate income tax, assuming its constitutionality is upheld.

The alternative which eliminates the ELF performs poorly, mainly because it results in higher effective severance tax rates for non-Prudhoe production. Since projected production rates per well for many of these fields are relatively low, (resulting in a low projected ELF), it appears that even relatively low effective severance tax rates may deter development of some marginal fields on the North Slope. We have noted that known deposits of heavy oil on the North Slope near the Kuparuk field possibly contain over 40 billion barrels of oil in place. None of this oil is being produced commercially at the present time, and any such development would clearly be only marginally profitable under reasonable price projections.

For the first stage of the hypothetical West Sak heavy oil development summarized above, our calculations showed a lack of economic feasibility, because developing the field would cost more than the value of the oil produced under the moderate price assumption. However, the present value of all excise taxes and royalties that would have to be paid by the producers to the State of Alaska is more than four times larger than the negative profit balance. Severance tax projections for this hypothetical development are very small (due to the ELF projected from low production per well of the heavy oil), despite its giant size. Under the development cost and price assumptions used for this field, the state’s royalty share makes the difference between feasibility and infeasibility.

The same problem may also be present with other smaller fields on the North Slope. Of course, it would be financially irresponsible for the state to offer to reduce its royalty share on the speculation that this might make production feasible from marginal fields. However, the state might consider ways to credit the capital costs of developing new North Slope heavy oil fields against the first royalty payments owed when production begins. The royalty credit could be converted into a modified net profit share by having the credit repaid with shares of lease income at a rate of, say, 30 percent. Such a program could provide the state with a large increase in revenue, if it stimulates production from new fields which otherwise would not occur.

All our scenarios projected that North Slope oil production would decline steadily in the 1990s, despite the addition of a number of large new fields. This follows from the inevitable decline in the enormous rate of current production from Prudhoe Bay. However, production from new fields commencing over the next 8 years will also be declining by the late 1990s. State and federal policies that affect the feasibility of Alaska North Slope petroleum development will play a major role in determining the rate and magnitude of this expected decline.
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