

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672  
1488 SCOMM 55: JNT. SPEC. COMM. ON STATE TAX POLICY, 1986-1987 1288

value, the federal price controls impose an artificial economic system on the crude oil producer. The limitation on the price for oil reduces the gross income that can be obtained by producing that oil, and the point where expenses overtake the permitted income is advanced from the true economic limit. This effect is especially acute when the production is mostly "old oil."

As an "old oil" producing property reaches the pseudo-economic limit imposed by the low "old oil" price, the production will be allowed a measure of pricing relief by allowing enough of it to receive "new oil" prices so as to return the producer to the same level of profitability that he had for that property in May 1973. As production costs continue to rise, this policy will eventually lead to the producer's entire share of production of the property being priced at the "new oil" prices. However, there is no increase allowed for the royalty owner's share, on the rationale that affording pricing relief to the royalty owner does not affect the production economics of the property. 20/ The effect of this is that the federal price controls, when confronted by a loss of production when a property reaches its pseudo-economic limit, will attempt to reset the pseudo-economic limit at ever higher price levels. The apparent maximum to this adjustment of the pseudo-economics is the pseudo-economic limit at the "new oil" price.

These economic and pseudo-economic effects can be illustrated in their application to hypothetical Field "A". Assume that "A" is in Cook Inlet producing "old oil" with a controlled price of \$4.855 (as most of Cook Inlet oil in fact is priced, for 34° API gravity oil). The royalty share, if based on this depressed price, represents a 61 cent cost ( $\$4.855 \times .125 = \$0.606875$ , rounded to \$0.61). The cents-per-barrel tax of \$0.3463 applies at "old oil" prices to seven-eighths (the non-royalty share) of the barrel, representing a cost of 30 cents per barrel produced. At "new oil" prices the tax is 54.25 cents ( $\$12.40 \times .875 \times 5\% = \$0.5425$ ). The combined per-barrel cost of the tax and royalty is 91 cents at "old oil" prices and \$1.15 with "new oil" pricing (no pricing relief would be given to royalty oil under prevailing federal policies).

The following graph plots the operating cost curve and the curve for operating costs plus royalty and tax. No capital costs are included because capital expenditures will be terminated when the costs approach the various price levels where price-controlled revenue equals total costs. Notice how the federal price controls create pseudo-economic limits well before the true economic limit based on real market value. By comparison the economic effects of the production tax and royalty are small.

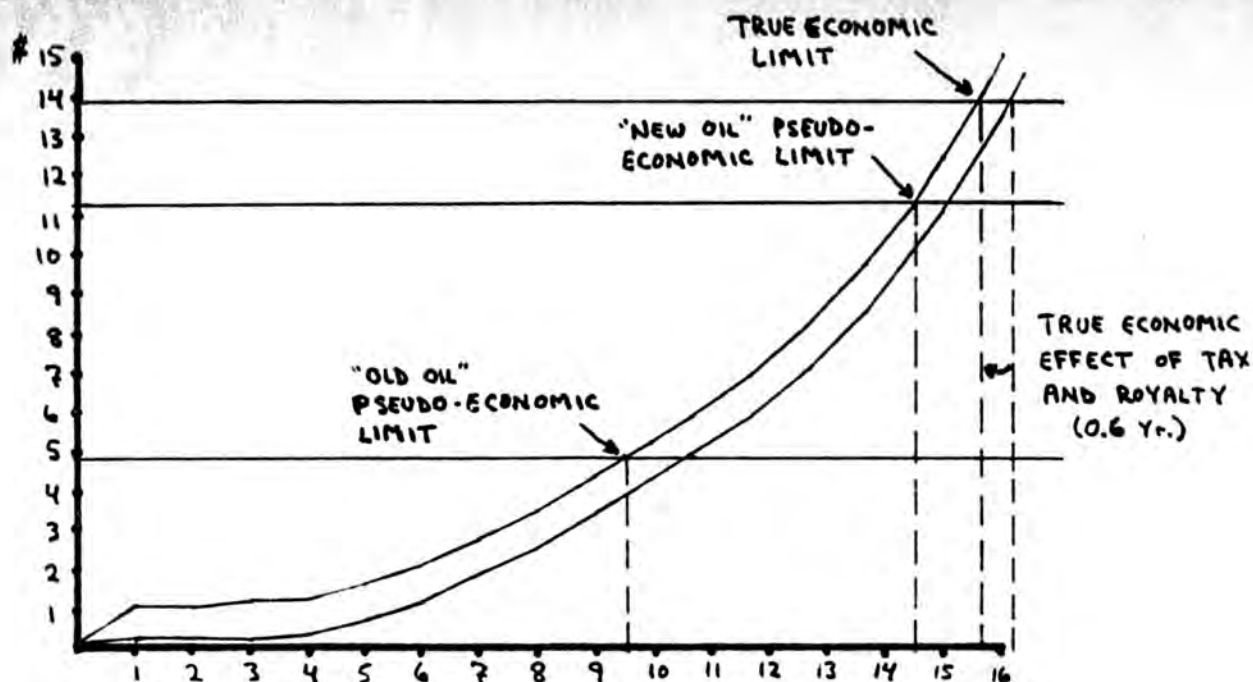


Figure V-2

2. Specific deficiencies in the present oil production tax. The existing State of Alaska crude oil production tax contains two flaws which should be and can be corrected. The first problem area concerns the present "stair steps" production tax rate schedule which establishes higher tax rates according to the productivity of individual oil wells. The second deficiency is related to the first and pertains to current difficulties in administering crude oil production tax collections. Each of these flaws can be remedied with relative ease. The result would be to create a more efficient and equitable oil production tax system.

The current State oil production tax contains a "stair step" feature which is intended to alleviate the adverse im-

pact that a production tax can have on an oil well operating close to its true economic limit. As was shown earlier with the Field "A" example, total operating and capital costs, together with royalty payments and production taxes, will ultimately rise to a point where profitable production operations based on true value can continue no longer. At this point the true economic limit has been reached and operations cease. The "stair step" feature of the existing oil production tax schedule is an attempt to reduce the tax rate as production falls closer to the true economic limit. The tax rate declines from 8% to 6% to 5% as individual well output falls. Unfortunately, the current "stair steps" appear to be sized incorrectly.

Economic factors governing production operations vary widely in the State of Alaska. Some areas in the State are located close to the refinery market and have low operating costs. In these areas wellhead values are high. As a consequence, the true economic limit (measured in barrels per day) for these properties can be quite low: 50 to 75 barrels a day per well, or even lower, in some cases in Cook Inlet.

Other crude oil wells in Alaska are not located close to refinery markets and could have extremely high operating costs. The netback value in the field for these isolated areas is lower than in Cook Inlet and the operating and capital costs can be much higher than in Cook Inlet. Accord-

ingly, the true economic limit (measured in barrels per day) for these producing properties can be quite high. Depending upon the property, this limit might range from 300 to perhaps 1000 barrels per day. There is, then, a rather wide range of values which can be generated regarding the minimum production level at which Alaska crude oil wells can be operated.

From this perspective, an economic flaw in the existing or any other "stair step" production tax schedule becomes obvious. By establishing a fixed schedule of "stair stepped" tax rates, the State crude oil production tax is based on the faulty assumption that production economics are similar in Cook Inlet, Prudhoe Bay, and everywhere else in Alaska.

This is not so. Diligent analysis at specific intervals may possibly produce a statewide "stair step" tax rate schedule which is consistent with the public interest as of the time of that analysis. As economic factors change, however, static systems such as the current one fail to adjust, and the "steps" will become inappropriate for Alaskan production.

A second problem area in the current State crude oil production tax concerns administrative difficulties. Under the current statutes, oil production taxes are collected on the basis of individual oil well productivity. Unfortunately, well tests are only performed periodically. Moreover, actual

crude oil flows are not metered for individual wells between well tests. As a consequence, individual well production must be allocated to specific wells on the basis of the periodic well tests. These tests may or may not be witnessed by State personnel. Since well conditions change through time, the accuracy of any particular well test cannot be verified by later testing. 21/ As a result, a complete audit of production tax payments is impossible due to lack of documentation. 22/ This administrative difficulty would be eliminated, however, if production taxes were based on averaged well production per producing property rather than the current well-by-well basis.

3. Protecting production tax revenue against manipulated oil prices. While the preceding section discussed the effects of the present production tax on the economics of oil production, the focus here is on the effectiveness of the tax as a reliable source of revenue for the State and on its safeguards against possible actions that would jeopardize that revenue. The greatest of those dangers is the manipulation of oil price, especially in regard to North Slope oil. There are basically two parties that might want to manipulate the price of Prudhoe Bay oil. One is the oil companies themselves, by inflating transportation costs and similar changes in order to lower the field price of the oil on which the tax is based. The other is the federal government, through price controls. In this section the various means available to the oil companies

are first discussed, along with the present safeguards against this. Then the present price control structure and the mechanics of the federal pricing decision for Prudhoe Bay are addressed, followed by an examination of the present tax's ability to deal with federal actions for North Slope and Cook Inlet oil production.

3-A. Corporate actions affecting price. To varying degrees some companies can retain control of their oil from the time it is produced until it is retailed as refined products. A company having this control is said to be vertically integrated. A vertically integrated company can, in a very real sense, choose which of its integrated operations - producing, transportation, refining or marketing - will be carried on the books as break-even or losing operations and which will be the sources of the profits of the overall enterprise.

A company's competitive position in one phase of operations can limit the extent to which income may be shifted to, or away from, that phase. Another influence can be royalty and production tax payments. If the field price 23/ of an integrated producer's production can be lowered as the result of shifting booked profits from production to some downstream phase of operations, the overall enterprise would lose nothing by doing so since it is merely moving money from one pocket to another. In fact it would actually have a net

gain since the lowered field price means that less royalty and production tax have to be paid.

Obviously decisions regarding the profitability of an integrated company's various interrelated activities would be made on the basis of many other factors besides the possible effects on royalty and production tax payments. Yet a company would be unlikely to fail to take advantage of an opportunity to realize royalty and production tax savings when that opportunity arises, even though entirely different considerations led the corporation to structure itself initially in the manner that now allows it to take advantage of the opportunity.

There seem to be three possible opportunities for some, but by no means all, of the companies owning interests in the Prudhoe Bay field to realize most or all of the benefits from the prevailing prices in the world oil market so dominated by OPEC while holding the line, so to speak, on production tax and royalty for that oil. These are in setting the TAPS tariff (or tariffs), in marine transportation costs and in marketing the oil to refiners outside the West Coast area. To some extent the State has protected its revenues against corporate actions in these areas, but there are serious gaps and weaknesses in that protection.

The danger most commonly perceived regarding TAPS is that excessive costs may be included in the rate base. The Interstate Commerce Commission (ICC), which regulates tariffs for crude oil pipelines in interstate commerce, is in the process of reviewing its tariff-setting procedures. This may be a positive step forward in terms of identifying excessive costs and eliminating them from the rate base, although the ICC's history of rate-making for pipelines may only lead one to a guarded optimism for the results of that review.

Anticipated to be a more diligent watchdog for Alaska's interests, the Alaska Pipeline Commission has authority to regulate TAPS tariffs to the fullest constitutionally permissible extent that it can do so. 24/ A risk remains, however, of pre-emption by the federal government. Moreover, even if not totally pre-empted, the Alaska Pipeline Commission would not regulate tariffs for oil moving in interstate commerce.

A question therefore arises if both agencies have rate-making powers regarding TAPS: Because the tariffs on file with either agency are prima facie reasonable under AS 43.55.150 for purposes of ascertaining value for production tax purposes, which tariff - the one filed with the ICC or the one with the Alaska Pipeline Commission - should be used for that purpose? Or, should each be used, for interstate and

intrastate shipments, respectively? A further complication comes from the fact that TAPS is a common facility for eight different pipeline companies, each with its own financial situation. It could well be that eight different tariffs will be filed with the ICC, while the Alaska Pipeline Commission might have eight more different tariffs. Which tariff or tariffs should be used then for valuation purposes under AS 43.55.150? Although the statute does not itself answer these questions, the Department of Revenue will be proposing draft regulations to deal with them at approximately the same time this report is published, and public hearings on the proposals will be announced for March.

Tankers may also afford some companies an opportunity to affect the field price for Prudhoe Bay oil. Some have chartered tankers to transport their oil from Valdez, but others may use their own ships. The inter-affiliate billings in the latter case would be subject to review by the Department of Revenue under AS 43.55.150 to prevent abuses and ensure that only reasonable costs of tanker transportation are recognized in the value of Prudhoe Bay oil for production tax.

The third opportunity results from the surplus of crude oil available to refiners on the West Coast that is expected to develop shortly after Prudhoe Bay production reaches 1,200,000 barrels a day. Much of this production will be refined on the West Coast. The surplus oil will have to

move to more distant U.S. refineries, if it is not sent to Japan in exchange for other oil shipped to U.S. ports on the Gulf of Mexico or Atlantic seaboard. The extra distance for that oil to move means greater transportation costs can be netted from the sales price at its destination to develop an implied price for the oil back at Prudhoe Bay. This means the field price will probably be lower for surplus Prudhoe crude than for the large amounts of Prudhoe oil that will be refined in West Coast refineries. A producer able to market only part of its Prudhoe Bay oil to its own refineries or others' on the West Coast can contend, quite persuasively, that traditional principles of economics limit the field market value of its entire share of production to that lower field price which is implied from the sales of the surplus crude oil marketed elsewhere at greater cost.

At present the State's only sure protection of its production tax revenues against reduction of the value due to the West Coast oil surplus would be the cents-per-barrel tax, which guarantees that production tax income will not fall below a specified level regardless how low the field price may go. Unfortunately, the latest cents-per-barrel rates protect the tax against reductions in the field price below \$6.10 25/ while the likely free-market field price (netting back from crude oil prices at West Coast refineries) will be substantially higher than this. Thus considerable production tax revenue would be foregone before the cents-

per-barrel provisions could begin protecting that revenue from further diminution.

3-B. Federal price controls, or, "Congress and the Teeter-totter". By April 15 of this year a decision will be made that is of far greater importance to Alaska than any corporate decision to take advantage of some opportunity to reduce its royalty and production tax payments to the State of Alaska. This is the decision regarding the pricing of all North Slope oil transported by TAPS. It will be made by President Carter and will be submitted on that date to Congress. 26/ The President's decision will become effective after 30 days unless either House of Congress rejects it within that time. 27/

Before proceeding directly to a discussion of the President's options and the standards he will apply in making this decision, it is helpful to explain how the present federal price controls apply to U.S. production other than that of the North Slope and then to explain how the decision regarding the North Slope oil interrelates to the price controls for the rest of domestic production.

Prior to the enactment of the Energy Policy and Conservation Act late in 1975, 28/ oil price controls created three categories of oil production. There was "old oil," "new oil" and "released oil." "Old oil" was first frozen

at its price level of mid-1973, but all "old oil" was allowed an increase of one dollar a barrel in December 1973. "New oil" and "released oil" were not controlled and were free to rise to market price levels, which rose rapidly because of OPEC price actions and the Arab oil embargo.

An apparent purpose of that pricing policy was to encourage increased domestic production by allowing the actual amount of the increase ("new oil") and an equal amount of the historic level of production ("released oil") to rise to the unexpectedly high market prices demanded by OPEC. To ensure that overall production from a property actually increased, the price controls specified that, for each month a property failed to produce the amount of oil as it did in the same month in 1972, the amount of this shortfall would be carried forward and deducted from any later months' increases until the shortfall was fully offset by those increases. Only when all past shortfalls were fully offset could production from the property be classified as "new" or "released" oil and receive higher prices.

By December 1975 these high, or "upper tier," prices were ranging from \$12 to \$14 a barrel. There was a range for "old oil" prices, too, since the "old oil" of each property was frozen at the actual mid-1973 price (plus the \$1.00 increase allowed in December 1973) for that

property's oil. Although \$5.25 was widely quoted as the "old oil" price, it was only the estimated average of all "old oil" prices. Some "old oil" was in fact frozen at a higher price; others were priced lower. <sup>29/</sup> The overall average price was reported to be \$8.75. Graphically, the pattern of prices for U.S. production by the end of 1975 looked like this:

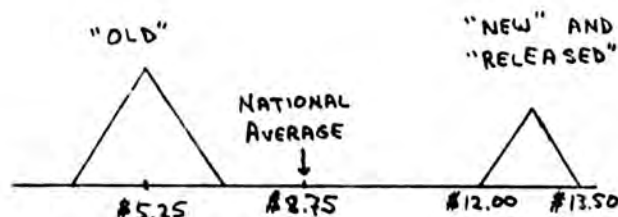


Figure V-3. The way we were.

With the enactment of the Energy Policy and Conservation Act, Congress changed this picture dramatically. Suddenly the whole pricing structure was transformed into an enormous teeter-totter, to be balanced on a reduced national average price of \$7.66 that Congress had chosen.

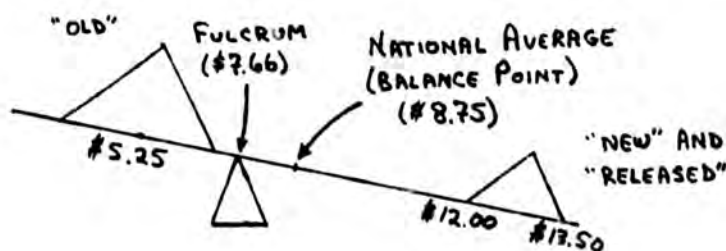


Figure V-4. How Congress built the teeter-totter.

Having decreed where the fulcrum must be, Congress left to the President and FEA the task of restructuring domestic oil prices so as to balance the teeter-totter on its new fulcrum. To assist in this, Congress extended price controls to "upper tier" crude oil.

The determination of "upper tier" oil was simplified by no longer offsetting accumulated monthly shortfalls before production could receive "upper tier" price. "Released crude" also ceased to be a category. Instead, "new oil" became simply that part of the monthly production from a property that exceeds the property's "Base Production Control Level" for that month, which is simply based on the amount of "old oil" the property produced during a particular reference period.

FEA and the President had from December 1975 to February 1, 1976 to accomplish the restructuring. 30/ They extended the two tier pricing system, holding the "lower tier" at \$5.25 and lowering "upper tier" prices so they averaged \$11.28. 31/

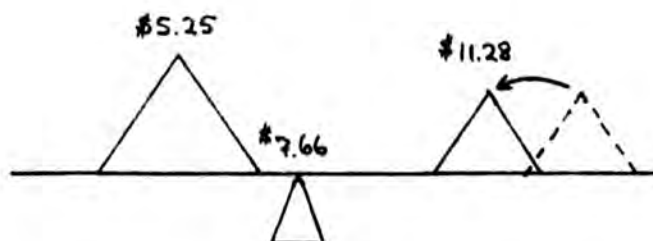


Figure V-5. How the President and FEA balanced the teeter-totter in February 1976.

Having struck this initial balance, FEA and the President had the further task of keeping the teeter-totter balanced while the fulcrum increases monthly at an annual compound rate to 10 percent. <sup>32/</sup> They began doing this by allowing both "upper tier" and "lower tier" prices to rise month by month under the following schedule:

|               | "Old Oil"<br>Increase<br>over 2/76 Level | "New Oil"<br>Increase<br>over 2/76 Level |
|---------------|------------------------------------------|------------------------------------------|
| February 1976 | --                                       | --                                       |
| March 1976    | \$0.03                                   | \$0.07                                   |
| April 1976    | 0.06                                     | 0.14                                     |
| May 1976      | 0.10                                     | 0.21                                     |
| June 1976     | 0.13                                     | 0.27                                     |

By June 1976, however, it became apparent that the 60:40 of "old" to "new oil" that had been assumed was in fact erroneous. Instead, there was a larger proportion of "new oil," which meant the actual balance point had moved ahead of where it should have been under the schedule ordered by Congress. To correct this FEA suspended its planned price increases, holding the prices for both tiers at the June levels until the scheduled balance point caught up with the actual one.

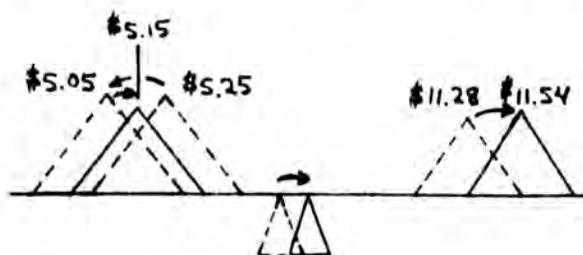


Figure V-6. How "old oil" was corrected to \$5.05 and how both tiers shifted upward by June 1976.



Figure V-7. The teeter-totter with "old," "new" (\$11.60) and "stripper" (\$11.63, but actually decontrolled) oil.

Unfortunately all this rebalancing did not help the actual balance-point get back within the 10 percent-a-year schedule that Congress prescribed for it. Under the law, any period in which the actual balance-point exceeds the schedule must be offset by a period in which the actual balance-point is below the schedule. 36/ Consequently FEA first extended until November 1976 the "hold" on escalating the basic "old" and "new" oil prices, then indefinitely. Finally, in January 1977, FEA announced a three-month roll-back of "new oil" to \$11.40 and "old oil" to \$5.15 (reducing the balance from \$8.34 to \$8.30) to compensate partially for the period when the actual balance-point exceeded the 10 percent-a-year schedule. To compensate for that period completely, the roll-back would have to extend until July 1977. However, FEA announced a shorter roll-back period because Congress will be reviewing the entire crude oil pricing teeter-totter this March. 37/ In addition the pricing of North Slope oil will be submitted to Congress by the President before the end of the currently announced roll-back period.

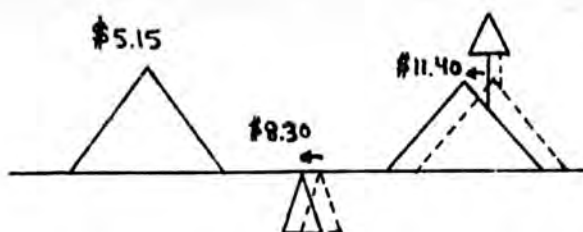


Figure V-8. The latest rebalancing, January 1977.

At this point it is appropriate to return to the matter of the pricing of Prudhoe Bay crude oil. The basic decision to be made is whether that oil should be put on the teeter-totter with the rest of U.S. production or whether it should be kept off and regulated separately.

The biggest factor affecting this decision is whether the price in the field for that oil is higher or lower than the balance-point of the teeter-totter. If its field price is lower than the balance point, the inclusion of that oil on the teeter-totter will mean that some oil currently in the "lower tier" can be allowed to receive "new oil," or possibly even decontrolled, prices.

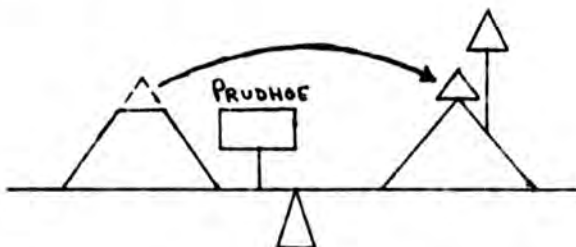


Figure V-9. How including Prudhoe oil could allow pricing relief to "old oil" while still balancing the teeter-totter.

On the other hand, if the field price of North Slope oil is greater than the balance-point, its inclusion would make the balance-point exceed the 10 percent-a-year schedule, and there would have to be another "hold" to allow the scheduled point to overtake the actual balance-point or else some of the "new oil" would have to be lowered in price.

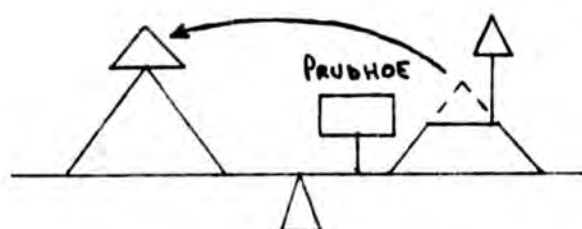


Figure V-10. How some "old oil" might be reclassified to maintain balance if North Slope oil is included and is above the balance-point.

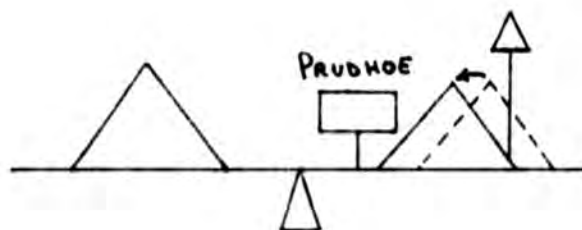


Figure V-11. How all "new oil" might be rolled back to maintain the balance if North Slope oil is included and is above the balance-point.

If such a "hold" or a lowering of oil prices proved to be slight, the President could keep Prudhoe oil on the teeter-totter even though its price were above the balance-point. However, if the President determines that keeping it on the teeter-totter

would...have the effect of reducing or limiting ceiling prices permitted for crude oil produced in the remainder of the United States to levels which would result in less production of such crude oil than would otherwise occur,

then he may recommend excluding it and subjecting it separately to price ceilings no higher than the "highest actual weighted average first sale price...for significant volumes of any other classification of domestic crude oil." 38/

It would be best for all concerned if the free-market field price for North Slope oil turns out to be less than the balance-point price (\$8.40 through April). In that case some "old oil" could be given pricing relief to keep the teeter-totter in balance, as illustrated in Figure V-9 above. This relief could be given in a way that encouraged marginal or high-cost production. At the same time, the free-market price for North Slope oil would, to the maximum extent short of subsidies, "provide positive price incentives for the development of [North Slope] crude oil production." 39/ It is likely that the free-market field price for Prudhoe Bay

oil will prove to be below the balance-point of the teeter-totter because of the high costs of transporting it to the refineries. 40/

It is not a sure thing, however, that the President and FEA will decide that a free-market price is necessary to provide adequate "positive price incentives" for North Slope oil development. Instead, it could be decided that a controlled price at a level below that of the free market yet high enough to provide a "fair" rate of return on North Slope investments provides the necessary "positive price incentives." With such a controlled price, putting Prudhoe Bay oil on the teeter-totter 41/ would allow an even greater upward shifting for other oil prices than there would be from the inclusion of Prudhoe oil at its free-market price.

In light of this possibility is is little comfort, from Alaska's perspective, to learn that a study has already been done for FEA about the range of prices that would yield a "fair" rate of return (discounted cash flow basis) on investments in the exploration, acquisition, development and pipeline transportation of North Slope oil. 42/ It concludes that a price as much as \$0.90 a barrel below the free-market price would provide an "equitable rate of return" on those investments. 43/ Ninety cents a barrel means a combined revenue loss for royalty and production tax of \$100,000,000

a year for the State when the main Prudhoe pool reaches full production. 44/

It should be pointed out that this is by no means the worst result that could be obtained through a discounted cash flow rate of return. Using the materials presented in Dr. Tanzer's study for the Alaska State Legislature, 45/ which excludes investments in TAPS from the base on which the rate of return is calculated, the field price would be below \$4.00 a barrel - less than half of the free-market price - if a rate of return of 15 percent before income tax were allowed as being fair. Dr. Arlon R. Tussing of the staff for the U.S. Senate Committee on Interior and Insular Affairs has repeatedly written that the total economic cost of producing North Slope crude and shipping it to West Coast refineries would be even less - around \$2.00 a barrel - and that the difference between economic cost and price represents "unearned bounty." 46/ Thus there is no dearth of support 47/ that could be cited by the President if he decided to suppress the price of North Slope oil below free-market levels in order to gain additional price incentives for other U.S. production. But the consequences for Alaska of that decision would be the loss of billions of dollars (see below).

3-C. Revenue implications. To provide an indication of the dollars-and-cents consequences of some of these oil-pricing

possibilities under present laws, computer projections have been made for the royalty and production tax revenues that the State would receive from Prudhoe Bay oil production if four of the possibilities were realized.

Case 1 is a free-market price case, 48/ providing a point of reference from which the consequences of the other three may be gauged. Case 2 represents a situation in which profit centers are shifted away from production operations as the result of a combination of corporate actions and federal price controls. 49/ A modified type of federal price controls - namely, establishing a ceiling price for oil at Valdez and holding it constant in nominal terms through time 50/ - underlies the forecast made in Case 3. 51/ The fourth case projects revenues under federal price ceilings based on the \$3.65 field price that is implicit under the assumptions of the "Tanzer report" if a "fair" pre-tax rate of return (discounted cash flow basis) of 15 percent is allowed. 52/

The following table shows the projected royalty revenues the State would receive under each of the four cases.

Alaska Royalty Income  
from Prudhoe Bay Main Reservoir  
(including income to be paid into Alaska Native Fund)  
(\$ millions)

|       | <u>Case 1</u> | <u>Case 2</u> | <u>Case 3</u> | <u>Case 4</u> |
|-------|---------------|---------------|---------------|---------------|
| FY 78 | 300.3         | 213.0         | 300.0         | 170.9         |
| FY 79 | 482.2         | 304.0         | 461.1         | 267.0         |
| FY 80 | 619.6         | 355.0         | 542.0         | 330.6         |
| FY 81 | 704.8         | 359.0         | 548.0         | 354.3         |
| FY 82 | 780.0         | 359.0         | 548.0         | 375.6         |
| FY 83 | 900.0         | 359.0         | 579.0         | 398.1         |
| FY 84 | 992.2         | 359.0         | 582.0         | 422.0         |
| FY 85 | 1030.2        | 359.0         | 582.0         | 447.3         |

The next table shows the projected production tax revenues the State would receive under these four cases.

Alaska Production Tax Income  
from Prudhoe Bay Main Reservoir  
(reflects application of EDIC for reserves tax)  
(\$ millions)

|       | <u>Case 1</u> | <u>Case 2</u> | <u>Case 3</u> | <u>Case 4</u> |
|-------|---------------|---------------|---------------|---------------|
| FY 78 | 78.5          | 71.0*         | 78.5          | 71.0*         |
| FY 79 | 127.0         | 114.5*        | 124.0         | 114.5*        |
| FY 80 | 163.0         | 143.2*        | 147.1         | 143.2*        |
| FY 81 | 247.9         | 152.3*        | 156.1*        | 152.3*        |
| FY 82 | 398.2         | 303.5*        | 303.5*        | 303.5*        |
| FY 83 | 467.3         | 336.1*        | 336.1*        | 336.1*        |
| FY 84 | 510.1         | 359.6*        | 359.6*        | 359.6*        |
| FY 85 | 551.2         | 375.1*        | 375.1*        | 375.1*        |

\*Indicates payment made on cents-per-barrel basis. Case 3 differs in FY 81 from Cases 2 and 4 because its greater earlier tax rates used up the EDIC faster.

The next table combines the results of the first two and shows how much less income the State would receive under Cases 2,3, and 4 than it would receive under free-market conditions.

|       | Lost Income<br>from Production Tax and Royalty<br>(\$ millions) |                               |                               |
|-------|-----------------------------------------------------------------|-------------------------------|-------------------------------|
|       | <u>If Case 2<br/>happens:</u>                                   | <u>If Case 3<br/>happens:</u> | <u>If Case 4<br/>happens:</u> |
| FY 78 | 94.8                                                            | 0.3                           | 136.9                         |
| FY 79 | 190.7                                                           | 24.1                          | 227.7                         |
| FY 80 | 284.4                                                           | 93.5                          | 308.8                         |
| FY 81 | 441.4                                                           | 248.6                         | 446.1                         |
| FY 82 | 515.7                                                           | 326.7                         | 499.1                         |
| FY 83 | 672.2                                                           | 452.2                         | 633.1                         |
| FY 84 | 783.7                                                           | 560.7                         | 720.7                         |
| FY 85 | 897.3                                                           | 680.3                         | 809.0                         |
| TOTAL | 3880.2                                                          | 2386.4                        | 3781.4                        |

4. Gas problems. In contrast to the oil production tax, Alaska's single rate, percent-of-value tax on gas production is strikingly uncomplicated. Except for occasional rate changes - the last was in 1970 - it is essentially unchanged since its original enactment by the Territorial Legislature in 1955.

This simplicity does not mean the tax is free from actual and potential problems. It does have a similar type of adverse impact on the economics of production operations as the oil production tax, although its simplicity means that this impact is not aggravated, as it is with certain of the complicating features of the tax on oil production.

The chief difficulties in the present gas production tax concern the valuation of the gas for tax purposes. There are two sources for problems. One is the long-term contracts often encountered in gas sales which, while adopting a price that initially reflects the market value, may become increasingly unrepresentative of that value as time passes during the term of the contract and market conditions change. The second source of problems for the State is price regulation by the Federal Power Commission (FPC).

Historically the market for gas production has been very different from that for oil. Often the gas purchaser is not affiliated with the gas producer, but instead is a pipeline company devoted primarily to the business of obtaining long-term commitments of gas supplies for its pipelines and shipping that gas from the field to the markets served by its pipeline system. <sup>53/</sup> For such a company to build its pipelines, it must have gas supplies committed for shipment through those lines for a time long enough to allow the investment to be recouped and a profit earned. (The tariffs charged and the profits earned are regulated by the FPC for interstate pipelines, and intrastate lines are generally regulated by those states.)

Gas sales contracts therefore tend to involve large, long-term commitments. It is not unusual to find them running for fifteen to twenty years or even longer. This

practice is reflected in Alaska. Contracts for gas in the Cook Inlet area run twenty years and longer, and long-term sales are also being discussed for gas from Prudhoe Bay.

In making a long-term sale, the producer and the buyer each make separate estimates of what the gas will be worth to him in the future. The producer must make a judgment about the price he might get for the gas 10 or 15 years later if it were not committed to his prospective purchaser; against that consideration he must balance the benefits of selling the gas now instead of finding another purchaser. Conversely, the buyer must assess the costs of the present contract against the possible costs if he must buy other gas at a later time. The negotiated price represents a compromise between the expectations of the two parties.

As the contract runs, conditions change. Newer contracts will reflect these changes, but the older agreements, and the expectations they incorporate, remain fixed. If the market price rises above the price provided in the older contract, the difference between the contract price and the market price represents a bargain to the purchaser. The benefits of this bargain increase the value of his contract right. For example, if the buyer has a contract right to buy 100,000 Mcf of gas at 24 cents an Mcf during the next year and the market price has gone to 45 cents an Mcf, the buyer will obtain \$45,000 worth of gas at a cost of only

\$24,000. The \$21,000 difference represents the value to him of his contract right to buy that gas at 24 cents an Mcf. The market value of the gas remains 45 cents an Mcf, however.

One interesting problem, which arises from a series of long-term contracts for gas production of a field, is the multiple pricing of gas production. Depending on which contract the gas is being produced for, it may have any of several different prices. In the Cook Inlet area, prices for gas from the Kenai gas field range from 17 cents an Mcf to approximately 45 cents. Other gas from the Inlet that is going to the same market as some of the Kenai field's gas is reported at over 60 cents.

While there may be a multiplicity of prices under the various contracts, there is theoretically only one market value at any given time. Theory in this case, it seems, may be controlling for production taxes, since the tax statute makes a distinction between price and value.

If oil or gas is sold under circumstances where the sale price does not represent the prevailing value...the department may require that the tax to be paid upon the basis of the value...

AS 43.55.020(f). The question of how the prevailing value should be determined is addressed in proposed draft regu-

lations of the Department of Revenue, which should be released for public examination and comment about the same time as this report. Public hearings on those proposed regulations will then be announced, probably for early March.

Compared to the gas resources at Prudhoe Bay, this problem in the production tax for Cook Inlet is insignificant. The estimated 27,000,000,000,000 cubic feet of gas reserves there represent an energy resource equivalent to approximately 4.5 billion barrels of oil. This roughly equals half the energy contained in the oil reserves of that field, and it represents an energy resource far larger than that contained in the remaining recoverable oil reserves of any other field in the United States. 54/ It has over 10 times the energy remaining in all the Cook Inlet oil reserves put together. 55/

The taxation of the enormous non-renewable gas resource of Prudhoe Bay therefore should merit similar care and attention as that given to the oil reserves there. In this regard, one may look at the present production tax rate of eight percent that will be imposed on most of the oil production and ask why the gas tax rate is only half that.

Because gas production from Prudhoe Bay will be a major source of revenue for the State of Alaska during the middle and late 1980's, it is prudent to protect those revenues from the effects of federal price controls, which

cannot be expected to be always administered for Alaska best revenue interests. The FPC has responsibility for regulating natural gas prices for interstate commerce. As with the oil pricing question, the FPC will have no difficulty finding published opinions to support an extremely low, or even negative, value for the gas in the field. 56/ A tax based on value, as the present gas production tax is, accordingly will not protect Alaska's revenues against such pricing actions by the FPC.

## C. PROPERTY TAX PROBLEMS

As explained in Chapter II, the State property tax on oil and gas equipment and facilities is really joint taxation by the State and the municipality (if any) in which the taxable property is located. The State, through the Department of Revenue, determines the assessed value of the property for the municipal property tax as well as for the State's tax. The municipality for its part is free to levy whatever millage it wants, subject to certain conditions already described in Chapter II.

In the three years of this tax, this arrangement has generally worked quite well. However, there are four areas in which the tax could be improved: the omission of certain important kinds of oil and gas related properties from the definition of taxable property; present uncertainty about how pipelines should be valued; the static nature of the \$1500 per-capita limitation of municipal taxation; and the extent to which credits against the State tax should be allowed for municipal property tax payments.

1. Omission from taxable property. The tax falls only on property used or committed for use in exploration operations, production operations or certain pipeline transportation operations. This limited range of the tax means that several major kinds of oil and gas related properties are not assessed

by the State, although they may still be subject to local property taxes if they lie within a municipality. These properties include such costly investments as oil refineries, gas processing plants, LNG facilities and petrochemical operations.

It may be said that these properties should be excluded from the State property tax as an incentive to would-be investors to locate their projects in Alaska. This contention overlooks two significant considerations that will be borne in mind by any prudent investor.

First, the incentive may not be all it seems to be. The exclusion of these types of property from the State's property tax does not mean that they are excluded from property tax levied by a municipality. A municipality may levy at rates up to 30 mills 63/ and even beyond that in certain circumstances. 64/ Since municipal property taxes are creditable against the State tax, excluding these properties from the State tax offers an incentive only when the municipal levy is less than 20 mills, and then the amount of that incentive is only the difference between the State and municipal millage rates. In fact, where the municipality levies at a rate above 20 mills, the exclusion from State property tax can act as a disincentive since the tax paid to the municipality is creditable against the State tax on taxable property not only within the municipality but

outside it as well. 65/ In other words the municipal levy in excess of 20 mills would be creditable against State tax on the taxpayer's property located elsewhere, thus holding the taxpayer's overall property tax rate at 20 mills statewide.

The second consideration of a would-be investor considering Alaska as a place to locate is that taxing jurisdictions not infrequently recognize that once a major investment of this kind is made, it is difficult to re-locate. Then the taxing authority need not hold out the enticement of tax exemptions any longer, especially when the exemption takes the form of a simple omission or exclusion from the definition of taxable property. The prudent investor should, therefore, look at the property tax rates on other, similar kinds of property and assume that his investment will be similarly taxed. This is exactly what El Paso has done in its filings with the Federal Power Commission regarding its proposal for transporting Prudhoe Bay gas. Even though LNG facilities are not currently taxed under the State property tax (and the proposed site at Gravina Point is not within a municipality with taxing powers), El Paso's cost projections include a 20 mill property tax on its LNG plant. 66/

After an investor has assumed he would pay property taxes and in fact no property taxes are imposed on his property, he gains an unforeseen windfall. This point is seldom lost on the taxing authority, which makes it all the

more likely that an investor will plan on property taxes being among the costs of his investment.

There is, therefore, no sound basis to support the notion that the present exclusions or omissions of the present property tax law need to be continued as an incentive for investments in Alaska. Without the incentive-based argument, no sound reason exists for continuing to exempt these kinds of oil and gas related properties from the State's property tax.

On the other hand, there is good reason to include those properties in the State's tax. For one thing, the property tax will be uniformly administered for these properties throughout the state, instead of allowing the taxpayers to play municipal assessors against one another by using a decision of one to under cut the position of another. And there would be additional income for the State from the properties already located in Alaska.

2. How to value pipelines. Under AS 43.56.060(e), pipelines may be valued on any of four different bases, depending on the circumstances. While a pipeline is being built, it is valued on the basis of actual costs incurred or accrued, but with no depreciation. 67/ After it begins operating, it is assessed "with due regard to the economic value of the property based on the estimated life of the

proven reserves ... then technically, economically and legally deliverable" to it, unless the "economic life" of those reserves is "materially shorter than the estimated physical life" of the pipeline. 68/ In the latter case, the operating pipeline is valued on the basis of actual costs with straight-line depreciation over its economic life (elapsed life 'since operations' began, plus the estimated remaining life of the deliverable reserves). If, for some reason beyond the pipeline owners' control, the pipeline cannot be used (or, during construction the construction is substantially or completely stopped) for at least 90 consecutive days during the year, then the pipeline's assessed value is to be "adjusted to take into account any diminution in value." 69/

The problem encountered in the administration of the tax has not been with the first or fourth cases, but with the valuation of pipelines operating normally. There seems to be some uncertainty as to when the economic life of the deliverable proven reserves is materially shorter than the "estimated physical life" of the pipeline, and no less than three different interpretations have been given so far to this condition. Some taxpayers have contended in their appeals to the Assessment Review Board that, with proper maintenance, their pipelines could last for 75, 100 or even 200 years and more and that this is the measure of the pipeline's physical life. Not surprisingly, this would

almost always cause their pipelines to be valued on the actual-cost-less-depreciation basis, which is lower than the assessment made with due regard to the economic value of their pipelines.

In administering the tax, the Department of Revenue disagrees with the taxpayers' interpretation of the words "estimated physical life." Instead, the Department regards that phrase as meaning the originally estimated life of the pipeline based upon the pipeline owners' expectations as to the economic life of the deliverable reserves when they began to build that pipeline. If the present estimate of the economic life of the deliverable reserves is materially shorter than the owners' original expectations, then in the Department's view the exception applies and the pipeline is to be assessed on the basis of its actual cost with depreciation. Otherwise, it is valued with due regard to its economic value.

The Assessment Review Board places still another interpretation on this phrase. To the Board, "estimated physical life" means the remaining economic life of the deliverable reserves, during which time the pipeline will be maintained, plus an additional time (such as three years) after the pipeline stops operating and maintenance ceases, during which the pipeline deteriorates to a point where it would no longer be capable of transporting oil (or gas, as the case may be).

Under the Board's reading, every pipeline will eventually qualify for the exception when the remaining economic life of the deliverable reserves becomes short.

With such divergent views as to the meaning of the statute, there is substantial uncertainty about which approach will be used to value pipelines generally and the Trans-Alaska Pipeline in particular. This uncertainty is a deficiency which should be corrected to assure a probable result for both the State and the taxpayers owning the largest asset taxable under the property tax. The value of TAPS will be too great to allow this uncertainty to be tolerated. Only one valuation method for pipelines operating normally should be allowed.

The valuation method chosen should be one which clearly reflects the full and true value of the pipeline property.

In the Department's view the use of the actual cost depreciated method does not accurately reflect the full and true value of the pipeline property. This method takes the actual costs incurred and depreciates them over the life of the proven reserves of oil or gas that are deliverable to the pipeline. The value of the property reaches its peak in the last year of construction and decreases ever after. While this method takes into account the reduction in value of the pipeline property over time it does not take into

account the increase in value as the result of inflation. Accordingly, some other method that takes inflation into account as well as depreciation, more accurately measures the value of these income producing assets. The value of a pipeline is not reflected solely by its historic cost and its declining reserves, but also by the current prices at which a replacement property would have to be purchased.

The difference between a method that takes into account appreciation as well as depreciation and one that accounts for depreciation only is displayed in the following table. This table shows the property valuations of the Trans-Alaska Pipeline under the two approaches for years 1978 - 1985, using a hypothetical life of 30 years for depreciation.

(Millions of Dollars)

|      | Actual Cost                  |       | Replacement Cost<br>(trended-10% yr) |       |
|------|------------------------------|-------|--------------------------------------|-------|
|      | (Less Depreciation - 30 yrs) |       | (Less Depreciation - 30 yrs)         |       |
|      | Value                        | Tax   | Value                                | Tax   |
| 1978 | 5,500                        | 110.0 | 5,500                                | 110.0 |
| 1979 | 5,317                        | 106.3 | 5,848                                | 117.0 |
| 1980 | 5,139                        | 102.8 | 6,219                                | 124.4 |
| 1981 | 4,968                        | 99.4  | 6,613                                | 132.3 |
| 1982 | 4,803                        | 96.1  | 7,031                                | 140.6 |
| 1983 | 4,642                        | 92.8  | 7,477                                | 149.5 |
| 1984 | 4,488                        | 89.8  | 7,950                                | 159.0 |
| 1985 | 4,338                        | 86.8  | 8,454                                | 169.1 |

As shown in the table a replacement cost method (appreciated approach) produces a valuation which is almost double the actual depreciated method by the year 1985. In view of the

uncertainties of valuation and a potential depressed valuation a change in the pipeline valuation method would appear warranted.

3. Municipal Limitations. As explained in Chapter II, the State's property tax provides more than just a revenue measure for the state. It sets an interface with municipal taxation by providing a credit against the property tax for property taxes paid to municipalities, and sets limitations on the amount of tax that may be imposed by the municipalities. Two problems are exhibited: one in the municipal limitations themselves, and the other in amount of credit which may be taken against the State's tax.

3-A. Static municipal limitations. The two municipal limitations set out in the statute are optional, and each year a municipality must choose the method or limitation which it will use. 70/

One limitation is a limitation on the municipality's total assessed value. A municipality may not levy a tax on the value of that portion of oil and gas properties assessed by the Department of Revenue which, when combined with the value of other property taxable by the municipality, exceeds 225 per cent of the average per capita assessed full and true value of property in the state multiplied by the number

of residents in the state. 71/ No municipality has yet elected this limitation.

The other is a limitation on the total taxes received by the municipality. 72/ Originally a municipality could not levy at a rate that would yield an amount of revenue from the total municipal property taxes that exceeded \$1000 times the number of residents in the municipality. In 1976 the Legislature raised the per-capita amount to \$1500. 73/

The shortcoming of the \$1500 per-capita limitation is that it is unchanging through time, even though inflation continues. As conditions change, this ceiling could be indexed to reflect those changes. A static ceiling may become unduly hard for a municipality faced with the task of maintaining or augmenting its services to its residents.

3-B. Municipal credit. In addition to the problem discussed above regarding the municipal limitations themselves, there is also a problem with the credit against the State's tax for property taxes paid to a municipality for the same property.

Under AS 43.56.010(d), a tax paid to a municipality under AS 29.53.045 may be credited against the state property tax. By regulation the Department of Revenue has interpreted this as meaning that taxes paid to municipalities on oil and

gas properties are creditable against the State tax up to the limitations of AS 29.53.045. Property tax levied under AS 29.53.055 by a municipality in excess of the limitations of AS 29.53.045 is not creditable against the State tax under regulations of the Department. 74/ For example, if a municipality makes a special levy under AS 29.53.055 for the purpose of pledging, paying or securing the payment of principal and interest on bonds, then the limitations of AS 29.53.055 and AS 29.53.050 do not apply to that levy. The total taxes levied by the municipality would exceed the two ceiling limitations discussed above for oil and gas properties. The taxes in excess of the limitations that are paid to the municipality are not creditable against the State's tax under the regulation.

If the taxes imposed in excess of the limitations were allowed to be credited against the State tax, it would mean an unnecessary reduction in State revenues. It would also lead to unequal treatment among taxpayers, giving preferential treatment to the large oil companies. For example, if a municipality levies a tax under AS 29.53.055 in excess of the ordinary limitations, all taxpayers will have to pay that special levy to the municipality for those debts. Taxpayers, however, who have oil and gas property assessed by the Department of Revenue would (in the absence of the Department's regulation) be able to credit their payments of the special levy against the State's tax, thereby paying

less overall tax than taxpayers who have non-oil and gas properties. 75/

The regulation is currently being challenged in the courts. 76/

#### D. RESERVES TAX PROBLEMS

The reserves tax has so far proved to be a highly successful, temporary addition to Alaska's oil and gas tax structure. Despite its success, the present reserves tax has several flaws which, although they so far have not caused problems, could lead to great difficulties if the tax were ever made permanent.

The first of these is the assessment of reserves before they are brought into production. Because large oil and gas properties are not bought and sold very often, the assessment of a property with proven reserves is a very detailed and difficult matter even when the property has a production history to rely upon. Individual well productivity, gas-oil ratios, water cuts and many other data from actual production are all analyzed to evaluate how the reservoir is performing and how it will perform in the future. Technical engineering expertise is required to project what efforts (and when) will be needed to assure maximum recovery, and the costs of those efforts must also be estimated. Economic advice, too, is needed to project not only gross revenues, but also to estimate when the economic conditions will develop that will terminate production operations. All this and more must be done to determine a year-by-year forecast of net proceeds from the reserves, which are then discounted to their present value in assessing those reserves.

This complex and arduous task is made even more so when there is no production data to rely upon. Increasingly, technical opinion (allbeit the very finest available) must substitute for actual production data.

The second drawback to the present tax is that the millage is set before the assessment is known. Worse, the assessing agency must submit revenue projections for the reserves tax after the millage is known but before the assessment is made. Ordinarily, other taxing jurisdictions set their levy after the assessments are known and the millage then produces the desired amount of revenue. The valuation of assessable properties is done fairly and impartially, as it must be, even when the millage has already been set. Accordingly, if the total assessed value proved to be higher or lower than estimated, the pre-set millage would have to be corrected to produce the desired tax revenue. The general practice of setting the millage after the assessments are known is simpler, since the millage is set more than once.

## Chapter V - Footnotes

- 1/ Milton Lipton, Testimony at the Joint Hearings on Proposed Oil and Gas Legislation before the House and Senate Resources Committees, Tuesday, March 23, 1973; Transcripts, p. 7.
- 2/ Jerome Zeifman formerly served as Chief Counsel to the Committee on the Judiciary of the U.S. House of Representatives, as well as Chief Counsel to the Special Subcommittee on State Taxation of Interstate Commerce.
- 3/ Kenneth Ainsworth was formerly an economist on the staff of the Special Subcommittee on State Taxation of Interstate Commerce. He has also served as a consultant in the revisions of the tax systems of New York City, the State of Connecticut and the District of Columbia.
- 4/ State Taxation of Interstate Commerce, U.S. House of Representatives Special Subcommittee on State Taxation of Interstate Commerce of the Committee on the Judiciary - June 15, 1964.
- 5/ Jerome M. Zeifman and Kenneth G. Ainsworth, The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax. January 1977.
- 6/ "Fifth Annual Corporate Tax Study," Congressional Record, Vol. 122, No. 151 - Part III.
- 7/ Zeifman and Ainsworth, op. cit., pp. 10-12.
- 8/ Ibid., p. 12.
- 9/ Fifth Annual Corporate Tax Study, Congressional Record, Vol. 122, No. 151 - Part III.
- 10/ In recognition of this conflict the Alaska Legislature repealed the applicability of the DISC exemption for Alaska income tax purposes. Sec. 3, ch. 153, SLA 1975.
- 11/ Zeifman and Ainsworth, op. cit., p. 13.
- 12/ AS 43.20.036(a).
- 13/ AS 43.20.036(b).
- 14/ AS 43.20.036.
- 15/ AS 43.20.021.

- 16/ AS 43.19.010, Article IV.
- 17/ Zeifman and Ainsworth, op. cit., p. 3.
- 18/ Ultimately the corporate decision-making turns on a subjective interpretation of the technical analyses, with greater or less weight being given to the positive points or the negative ones. At this point, a negative attitude induced by what the decision-maker perceives as a harsh or unfair tax climate can color the entire decision and dampen enthusiasm in the bidding. Conversely optimism, bolstered by encouraging speculation about a structure with large potential, can drive the bidding to great heights, as witness the 1969 oil and gas lease sale.
- 19/ There is a third category, "stripper well oil," for production from wells at less than 10 barrels a day. It is unimportant to Alaska, although there are thousands of stripper wells Outside. The federal controls of crude oil prices are more fully discussed later in this chapter.
- 20/ These policies were presented to representatives of the Department of Revenue by Gorman Smith, Assistant Administrator of the FFA, and Edwin P. Mampe, FEA's director of price regulation.
- 21/ Periodic well testing does provide a sort of base line against which a particular test may be compared to obtain, in a gross sense, some feeling for its reasonableness. A well test that suddenly and greatly diverges from the results of previous tests may reflect some breakdown of the test rather than a sudden change in the condition of the well, unless its results are confirmed by further testing. But the "feel" acquired from a history of well tests hardly approaches the degree of accuracy needed for the detailed tax calculations that are based on those well tests, and an audit of those calculations cannot be satisfactorily conducted in reliance on that "feel."
- 22/ The inability to conduct complete audits of the production tax has been a concern of the Audit Division of the Legislative Budget and Audit Committee, as well as the Department of Revenue.
- 23/ The term "field price" is used in place of the commonly used phrase "wellhead price" to avoid the misleading connotations of the latter expression. In a field with high production volumes and a simple pattern of land ownership, as is often found in Alaska, operations for separating the oil, water and associated gas and

for reducing basic sediments, salts and water to acceptable levels are more economically conducted at one or more central facilities than at separate, small installations at each wellsite, as is done in many fields in the Lower 48. Thus, where the "wellhead" facilities are replaced by larger, more efficient ones at a central location, the price of the production that corresponds to the price at the "wellhead" facilities is the price at the central facilities. The term "wellhead price" carries over from areas where lower production rates or more complex patterns of land ownership led to on-site facilities for each well. In a field with centralized facilities, therefore, "wellhead price" should be understood to mean the price at those facilities, reflecting the fact that the field production operations have been centralized. However, it still suggests the individual wellheads. "Field price" avoids this suggestion and the misunderstanding that may result from the other term.

- 24/ AS 42.06.150.
- 25/ Prudhoe Bay oil is expected to be 27° API gravity, for which the latest cents-per-barrel rates are \$0.3051, \$0.3662 and \$0.4883. If the field price is \$6.10, 5% of it is \$0.3050, 6% is \$0.3660 and 8% is \$0.7880 - which are \$0.0001, \$0.0002 and \$0.0003, respectively, below the cents-per-barrel rates. Thus, at a \$6.10 field price for Prudhoe oil, the cents-per-barrel tax would have just begun to take over as the basis for production tax payments.
- 26/ Energy Policy and Conservation Act of 1975, Public Law 94-163, Title IV, sec. 401(a); codified in pertinent part as 15 U.S.C. sec. 757. The provisions relating to the time and nature of the report are in 15 U.S.C. sec. 757(g) (1)-(3).
- 27/ 15 U.S.C. sec. 757(g) (3); 42 U.S.C. sec. 6421.
- 28/ The changes in price controls under Public Law 94-163 took effect midnight December 15, 1975.
- 29/ Production in the Cook Inlet area was frozen at a lower price than \$5.25. Even today, after FEA has allowed some price increases since February 1976 for "old oil" and has given some extra relief for California and Alaska crudes by closing the price differential from 5 cents to three for each degree of API gravity below 40°, the ceiling price for over half of the Inlet's production corresponds to a value \$4.855 for 34° crude.
- 30/ 15 U.S.C. sec. 757(a).

- 31/ It was believed then that 60% of U.S. oil production was "old oil" as of February 1, 1976 and that the average "old oil" price then was \$5.25. On this assumption, an average price of \$11.28 for the "upper tier" yields the prescribed \$7.66 average price for both tiers.
- 32/ Originally the annual rate of increase was the sum of the percentage increase of the GNP deflator and a 3% incentive, with the sum limited to 10 percent. This was changed to the simpler 10% yearly rate by the Energy Conservation and Production Act, Public Law 94-385, sec. 122(1), effective August 14, 1976 and codified as 15 U.S.C. sec. 757(d)(1).
- 33/ Public Law 94-385.
- 34/ 15 U.S.C. sec. 757(j)(1).
- 35/ 15 U.S.C. sec. 757(i)(1). Stripper-well crude is oil "from a property whose maximum average daily production of crude oil per well during any consecutive 12-month qualifying period after December 31, 1972, does not exceed 10 barrels." 15 U.S.C. sec. 757(i)(2).
- 36/ 15 U.S.C. sec. 757(c)(2).
- 37/ The President is to report to Congress February 15, 1977 on the effects of decontrolling "stripper-well" oil. On March 15, 1977, he may submit proposals to change any part of the whole structure, which will take effect unless rejected by either House. 15 U.S.C. sec. 757(f).
- 38/ 15 U.S.C. sec. 757(g)(2). When enacted, this reference to the "highest actual weighted average first sale price" was probably to "new oil" prices. However, with the enactment of the Energy Conservation and Production Act in August 1976, the "stripper-well" classification was established, and the actual "first sale" price for this classification is decontrolled.
- 39/ 15 U.S.C. sec. 757(g)(1) and (2).
- 40/ A tabulation and explanation of how the market would set the field price for Prudhoe Bay oil are given in Chapter IV.
- 41/ The President has not indicated he would, but he certainly could, establish a special price ceiling for North Slope oil and still include that oil on the teeter-totter. 15 U.S.C. sec. 757(b)(1) states that the pricing regulation "may...provide for different ceiling prices (or manner of determining ceiling prices) for different classifications of crude oil...." The only limit to the President's

reclassifying power are that any reclassification be "administratively feasible" and that it be "consistent with obtaining optimum production of crude oil in the United States." 15 U.S.C. sec. 757(b)(1)(A) and (B). Neither of these would prevent the President from first creating a third pricing tier especially for North Slope oil with a controlled price less than market value yet still allowing a "fair" rate of return, and then including that tier with the rest of U.S. production on the teeter-totter.

- 42/ Mortada International, The Determination of Equitable Pricing Levels for North Slope Alaskan Crude Oil (November 1976).
- 43/ "A price at Valdez falling between 11.50 and 12.40 \$/B [in 1976 dollars] provides an equitable rate of return to the owners of Prudhoe Bay Field and TAPS... Under present tariff expectations, a well head price between 7.00 and 7.90 \$/B in 1976 dollars, to be adjusted quarterly for inflation, would be equivalent to a Valdez price of 11.50 to 12.40 \$/B." Mortada International, op. cit., pp. VII-6 to VII-7. Elsewhere that study concludes that North Slope oil is, from a refiner's standpoint, comparable in value to Saudi Arabian Light crude (pp. ii-11 to II-17), and that the market price at Valdez, corresponding to the cost to a West Coast refiner for Saudi Arabian Light, is \$12.40 (p. III-12).
- 44/ Assuming production of 1,600,000 barrels a day and an effective production tax rate of 7.5%.
- 45/ Tanzer Economic Associates, Inc., Alaska's Prudhoe Bay Oil: Profitability and Taxation Potential (January 9, 1976).
- 46/ Crude oil from Alaska's Prudhoe Bay field will be laid into the West Coast of the United States at an economic cost of around \$2. I believe that we can expect that field to be joined very soon by other very large (and consequently very low cost) reservoirs in Northern Alaska.

Arlon R. Tussing, "The Price of Petroleum," The Conference Board Record XI (September 1974), pp. 12-14.

Because a large proportion of total supply will be produced at a cost substantially lower than the prevailing price, the energy industries will continue to generate vast unearned profits (differential rents) for those who control resources that can be developed at low cost....This unearned bounty - the difference between cost and price on an ever-growing volume of production - will total tens of thousands of millions of dollars [worldwide] each year.

Arlon R. Tussing, "Three Classes of Energy Resources," Energy Policy (September 1974), pp. 174 et seq. As far as Dr. Tussing is concerned, any price for North Slope oil over \$2 a barrel would represent more than a positive price incentive for North Slope development, although he would allow the price to rise above \$2 a barrel to a price equal to the highest economic cost for an energy supply needed to meet U.S. energy demand. See, e.g., Arlon R. Tussing, "New Priorities for Energy and the Environment," The Northern Engineer, VI (1974), pp. 6-7; "Three Classes of Energy Resources," loc. cit.

47/ Inadvertently the Alaska State Legislature has exposed itself to citation in support of artificially suppressed North Slope oil prices because of the publicity in the Wall Street Journal and elsewhere regarding its consideration in the last Session of "excess value" taxes. A Bill to tax the "excess profits" to be realized by free-market prices for Prudhoe Bay oil is predicated on a determination that the free-market price will be unjustifiably high.

48/ The assumptions underlying the development of the free-market price projections were explained and tabulated in detail in Chapter IV.

49/ This case represents a combination of federal pricing decisions and corporate ability to adapt to the opportunities presented by those decisions. In it, the TAPS owners begin operations and file tariffs with the ICC using calendar years as their accounting basis. Throughput for the year is low because it is zero until mid-year and reaches 1.2 million barrels a day only when it is very late in the year. This sets the tariff initially at a very high level, allowing ICC to make a show of lowering the tariff to satisfy public opinion while leaving it still high enough to allow most or all of this total TAPS costs in the rate base.

FEA, in making its pricing decision, not only uses the initial tariff filed for TAPS to net back to Prudhoe Bay from the market, but it also points to the West Coast surplus, states that it is the surplus oil which determines the economic value of the rest of the oil, and then says the Gulf of Mexico is where the surplus will go. Gulf of Mexico prices for imported crude oil are not much higher than for the West Coast, so in effect nearly all of the extra costs of getting the surplus oil to the Gulf coast would represent a reduction in the field price for Prudhoe Bay.

Putting numbers to these assumptions yields the following for the initial pricing of North Slope oil:

|                                                         |             |
|---------------------------------------------------------|-------------|
| Price of Saudi Arabian<br>crude (31°), FOB Ras Tanura   | \$11.56     |
| Tanker tariff to U.S. Gulf<br>of Mexico coast           | <u>1.83</u> |
| Cost to Gulf Coast refiner                              | \$13.39     |
| Tanker tariff: Valdez to Gulf<br>Coast via Panama Canal | <u>2.25</u> |
| "Netback" price at Valdez                               | \$11.14     |
| TAPS initial tariff                                     | <u>5.92</u> |
| "Netback" price at Prudhoe                              | \$ 5.22     |

In running the model, the Prudhoe "netback" price was rounded to \$5.25.

As one final assumption: FEA determines that this is not only the market price, but is also a "fair" or "just" price on the basis of discounted cash flow rate of return analysis for the field development investment only (TAPS investment excluded). It then holds the price at \$5.25.

As FEA has already decontrolled all major refined products except gasoline (and gasoline prices nationwide are not now at the ceiling), there is "play in the joints" to allow the integrated companies to assign the profits to downstream operations.

Prudhoe Bay production is assumed to be unchanged.

50/ This was a recommendation of the "equitable pricing" study done for FEA (Mortada International, op. cit., pp. viii, VII-6), except that it suggested holding the price constant in real terms (i.e., allowing it to rise through time just enough to offset the effects of inflation.

51/ In this case, FEA regulates the price at Prudhoe Bay by controlling the price at Valdez. This simplifies its problems arising from possibly more than one TAPS tariff. It was recommended by the "Mortada report."

52/ This case is a kind of middle ground between the \$5.25 price of Case 1 and Dr. Tussing's declarations about a \$2-a-barrel laid-in cost at the West Coast for North Slope oil. It uses a \$3.65 price, which is the price that would yield a 15% rate of return under Dr. Tanzer's model. Production rates are the same as for the other three cases.

- 53/ Because gas supplies in the United States have dwindled at an alarming rate, some pipeline companies have been joining exploratory ventures in hopes of discovering for themselves secure supplies of gas in the future.
- 54/ There are 13 fields in the United States whose remaining proved recoverable oil reserves, plus cumulative production, total 1,000,000,000 barrels or more. Of these only four had remaining reserves in excess of a billion barrels at the beginning of 1976: Prudhoe Bay field, Alaska (9.6 billion); East Texas field, Texas (1.69 billion); Elk Hills field, California (1.05 billion); and the Santa Ynez Unit, California (1.0 billion). The Yates field in Texas had 0.98 billion. Source: "Here are the Big U.S. Reserves," Oil & Gas Journal (January 26, 1976), pp. 118-120. One cubic foot of gas contains about 1000 British thermal units (Btu), while a barrel of oil contains somewhat less than 6,000,000 Btu. The Prudhoe Bay gas thus represents some 27 quadrillion (27,000,000,000,000,000) Btu, while the East Texas field - largest U.S. oil field after Prudhoe Bay - has 10 quadrillion Btu represented by its remaining reserves.
- 55/ In the survey cited in the preceding footnote, fields in the Cook Inlet area were reported to have a total of 407,600,000 barrels of remaining reserves, exclusive of the Trading Bay and Beaver Creek fields. These do not have enough remaining reserves to push the total to the 450 million barrels of oil that would represent one-tenth of the energy content of the Prudhoe Bay gas.
- 56/ ...the range of practical discretion available to the [Federal Power] Commission in setting of a wellhead price may be slim or nil. It is by no means obvious that the array of prices at which the entire gas production of the Prudhoe Bay field could be sold would cover a cost of service transportation tariff, and leave anything at all for a wellhead price. That is, the netback value in the field of North Slope gas delivered to the Lower 48 may well be zero or negative!

Arlon R. Tussing, Analysis of Transportation Proposals for North Slope Natural Gas (Report to State of Alaska, Office of the Attorney General - March 31, 1975 draft), pp. 33-34 (original emphasis). Relying heavily on this analysis, Governor Hammond testified on February 2, 1976 before the Federal Power Commission about his concern that the value of the gas in the field may be "very small indeed." Subsequently Dr. Tussing made a subtle qualification of his original position:

While it is still accurate to say that the wellhead value of the gas, squeezed between the market price and very high transportation costs, may be "very low indeed," it no longer appears likely that the wellhead price could fall below about 50 cents per thousand cubic feet, if any gas is sold for interstate shipment.... The crucial new information [that "became available after I made my original report"] concerns the additional cost of producing gas for sale.... Unless the operating companies receive a high enough price for gas at the wellhead to offset these costs, together with any operating costs associated with preparation of the gas for pipeline transportation, it would not be rational for them to make the investments necessary to make the gas available for sale.... There is still a danger that transportation costs will be so high that the "netback" value of the gas will be low (less than 50 cents), zero or even negative. Indeed, that danger seems even greater now than it did at the time I wrote the report to the task force.

Arlon R. Tussing, "Qualification of Analysis Regarding Wellhead Price of North Slope Natural Gas" (Memo to Attorney General Avrum Gross - February 27, 1976).

- 57/ AS 29.53.050(a).
- 58/ AS 29.53.055(a).
- 59/ AS 43.56.010(d); 11 AAC 05.840.
- 60/ El Paso Alaska Company, Trans-Alaska Gas Project Socio Economic Analysis (August 1975) p. 17.
- 61/ AS 43.56.060(e)(1). While construction is ongoing, costs incurred solely for construction facilities (as opposed to permanent facilities of the pipeline itself or comprising part of an overall, integrated pipeline system) are factored increasingly into the assessed value as construction progresses toward completion. 11 AAC 05.890(b)(1).
- 62/ AS 43.56.060(e)(2).
- 63/ AS 43.56.060(e)(3).
- 64/ AS 29.53.045 and AS 29.53.050.
- 65/ AS 29.53.045(c).
- 66/ AS 29.53.045(b).
- 67/ Sec. 8, ch. 107, SLA 1976.

68/ 15 AAC 05.840.

69/ A similar problem exists when a municipal levy exceeds 20 mills. The taxpayer is then able to offset the tax in excess of 20 mills against the State tax paid on property located elsewhere in the state.

70/ SOHIO Pipe Line Co. et. al., v. North Slope Borough and the State of Alaska, Superior Court 76-5027.

CHAPTER VI. RECOMMENDATIONS

## A. RECOMMENDATIONS FOR THE CORPORATE INCOME TAX

As discussed in Chapter V, the corporate income tax has two deficiencies: (1) the use of the eroded federal income tax base, with its incentives that are unrelated, inappropriate or sometimes even hostile to the policies and objectives of the State, and (2) the use of the destination-oriented sales factor, which does not truly reflect oil and gas production activity in the State.

The Federal Eroded Tax Base. To solve the problem of the federal eroded tax base the Department of Revenue recommends the Zeifman and Ainsworth proposal for substituting a new tax base measured by "book income." Specifically, a franchise tax should be imposed on corporations of a certain size that are engaged in the production, transportation and/or refining of oil or gas in Alaska. This new tax would be in lieu of the corporate income tax and would be measured by the net income, before deduction of income taxes, of a corporation as reported and independently certified to its stockholders (book income). In addition to the basic "book income" base, the State should adopt its own special tax incentives specifically tailored to Alaska policies and goals. This would solve the problem of the eroded tax base by eliminating all present and future federal tax incentives, subsidies and accounting devices developed specifically in response to the federal tax law. The erosions are eliminated since a corporation's

book income is determined by normal rules of accounting independently and without reference to federal tax law.

Although there would be some flexibility in determining net income from corporation to corporation based upon different accounting rules and methods, there are real deterrents against manipulating "book income" for state tax purposes. "Book income" is subject to certification under rules promulgated by the American Institute of Certified Public Accountants and is subject to review by the Securities and Exchange Commission. In addition, since a corporation's first allegiance is to its stockholders, it is improbable that manipulations would be made in the computation of "book income" to lower the Alaska tax liability at the expense of the corporation's stockholders. In addition, the demands of creditors and corporate bond holders would also be a constraining force on any attempt to lower a corporation's book income for state tax advantages.

The effectiveness of eliminating the federal erosions by switching to a franchise tax measured by "book income" is shown in the Zeifman and Ainsworth Report. They found in the sample of large oil corporations doing business in Alaska that book incomes exceeded federal taxable incomes by 1.6 to 3 billion dollars a year over the last three years.

The specific difference between book income and federal

taxable income is shown in a table from the Zeifman and Ainsworth Report:

DIFFERENCE BETWEEN BOOK INCOME AND TAXABLE INCOME  
FOR A SAMPLE OF OIL COMPANIES OPERATING IN ALASKA

| <u>Company</u> | <u>Difference<br/>1973<br/>(thousands \$'s)</u> | <u>Difference<br/>1974<br/>(thousands \$'s)</u> | <u>Difference<br/>1975<br/>(thousands \$'s)</u> |
|----------------|-------------------------------------------------|-------------------------------------------------|-------------------------------------------------|
| A              | NA                                              | 221,219                                         | 38,825                                          |
| B              | 177,629                                         | 208,882                                         | 129,451                                         |
| C              | NA                                              | NA                                              | 17,009                                          |
| D              | 39,814                                          | 34,204                                          | NA                                              |
| E              | 166,769                                         | 242,587                                         | 150,231                                         |
| F              | 193,072                                         | 368,175                                         | 110,248                                         |
| G              | NA                                              | NA                                              | 464,781                                         |
| H              | 335,080                                         | 448,695                                         | 608,333                                         |
| I              | 84,495                                          | 93,351                                          | NA                                              |
| J              | (61)                                            | (333)                                           | 72                                              |
| K              | NA                                              | 46,338                                          | (120,374)                                       |
| L              | 261,888                                         | 280,454                                         | NA                                              |
| M              | 278,634                                         | 784,519                                         | 193,439                                         |
| Total          | 1,834,298<br>(4 cases<br>not available)         | 3,056,434<br>(2 cases<br>not available)         | 1,592,015<br>(3 cases<br>not available)         |

In addition to eliminating the federal erosions, the use of "book income" also eliminates conflicting and non-responsive federal tax incentives. Since the State begins with a clean slate (book income), the Alaska Legislature is free to establish its own taxation policies consistent with Alaska's specific interests and objectives, instead of contending with federal tax policies that are now being incorporated into the State's tax.

The Department does not recommend one other possible solution - adding back to federal taxable income all non-

desired erosions (federal tax incentives, subsidies and other tax accounting devices) which conflict with Alaska policies. Although this alternative would effectively eliminate all current non-desired erosions in the tax base, it would leave open the door for incorporation of future federal erosions which the Alaska Legislature would have to constantly review and excise.

The Inappropriate Apportionment Formula. As explained in Chapter V, the destination sales factor in the current apportionment formula does not truly represent oil and gas production activity in the State. Therefore, the Department of Revenue recommends the second proposal made by Zeifman and Ainsworth for adopting an extraction factor as a part of the State's apportionment formula to measure the value of production in Alaska. Specifically the Department recommends adopting an extraction factor as a substitute for the sales factor or alternatively as an additional fourth factor to the uniform apportionment formula. This extraction factor would be a fraction, the numerator of which would be the number of units of oil and gas (determined by BTU parity) produced in Alaska and the denominator would be the number of units of oil and gas produced everywhere. Thus if the total units of oil and gas produced in Alaska were 10,000,000 for a particular oil corporation and its total units of oil and gas produced everywhere were 50,000,000, its extraction factor would be:

$$\frac{10,000,000}{50,000,000} \text{ or } 20\%$$

First this solves the problem of the reduction in the apportionment formula by the current sales factor. The current sales factor only assigns to Alaska the sales of petroleum products actually destined in Alaska. Since destination sales in Alaska are insignificant compared to total sales, the resulting small sales factor reduces the overall apportionment formula. By substituting or adding the extraction factor the overall apportionment formula is increased, resulting in more taxable income being assigned to Alaska. Specifically, Zeifman and Ainsworth show that the origin oriented extraction factor is substantially larger than the current sales factor and that its use would add more than 50 million dollars of Alaska apportioned taxable income for the 13 largest oil corporations doing business in Alaska. The pertinent table showing this effect follows:

APPORTIONMENT RATIOS BASED ON THREE FACTOR FORMULAS  
I.E. PROPERTY, PAYROLL AND SALES, AND  
PROPERTY, PAYROLL AND EXTRACTION  
(Worldwide Ratios for 1975)

| <u>Company</u> | <u>3 Factors<br/>Sales Destination</u> | <u>3 Factors<br/>Origin</u> | <u>Tax Base Differences<br/>(Origin-Destination) \$'s</u> |
|----------------|----------------------------------------|-----------------------------|-----------------------------------------------------------|
| A              | .003                                   | .008                        | 4,370,713                                                 |
| B              | .002                                   | .002                        | 1,711,849                                                 |
| C              | .021                                   | .034                        | 8,979,919                                                 |
| D              | .010                                   | .011                        | 21,705                                                    |
| E              | .013                                   | .027                        | 2,628,601                                                 |
| F              | .014                                   | .025                        | 2,031,795                                                 |
| G              | .001                                   | .002                        | 5,869,087                                                 |
| H              | .006                                   | .010                        | 3,888,539                                                 |
| I              | .004                                   | .009                        | 455,548                                                   |
| J              | .005                                   | .011                        | 3,982,088                                                 |
| K              | .014                                   | .030                        | 2,669,889                                                 |
| L              | .032                                   | .056                        | 11,769,255                                                |
| M              | .035                                   | .048                        | 4,229,968                                                 |
|                |                                        | TOTAL                       | 52,608,956                                                |

In addition to the increased apportioned tax base which the extraction factor would create, it would for the first time provide a measurement of production activity in Alaska since the factor is based upon units of oil and gas produced. Currently, the sales factor only measures marketing activity of oil and gas corporations since it is based upon destination sales.

By making this modification to the formula instead of adopting a separate accounting method, the State could continue combining the total taxable income of the unitary business. By looking at the entire enterprise and eliminating inter-company transactions, it effectively eliminates the effects of inter-company manipulations of income and expense.

The Department does not recommend two other possible modifications of the apportionment formula or the use of separate accounting because of the problems which they present. One of the possible alternatives would be to change the definition of "destination" in assigning sales for purposes of the sales factor. A change in the definition of "destination" could be made so that a sale would be destined in the state once the oil and gas produced was transferred to a transportation facility. Although this modification would measure production activity in the state, its application would present extreme administrative difficulties. For example, some sale price would have to be assigned for the oil and gas produced and that price would either be the final sales price to the consumer or an imputed price at the point where the production is transferred to the transportation facility. If the first course was chosen, the Alaska production would have to be traced all the way to the market and a final sales price determined for each unit of oil and gas produced in Alaska. In the second case, a value would have to be assigned to all production everywhere at the point where it was transferred to the transportation facility. Each alternative would be so difficult as to be unworkable.

Another alternative modification of the apportionment formula which is not being recommended would be the elimination of the sales factor entirely from the apportionment

formula. The remaining two factors of payroll and property would then be used to apportion income to Alaska. The elimination of the sales factor would benefit Alaska since it is this factor which reduces the overall apportionment formulas of most multistate oil and gas corporations. As shown by Zeifman and Ainsworth, the use of the two factor formula would add \$25 million dollars of Alaska taxable income.

Although the use of a two factor formula would prevent the present reduction in the apportionment formula using the sales factor, it would not measure the value of oil and gas produced in the state. Thus, the corporation's activity in the state would be measured solely by the corporation's property and payroll in Alaska.

In addition to the two alternative modifications of the apportionment formula, the Department also strongly recommends against the use of separate accounting.

Separate accounting separates or segregates the net income of a business into geographical units. In effect, the business activities in one state are treated as if they were carried on by a totally separate business. The separate accounting method involves the specific identification of only those items of income and expense which relate to the taxpayer's activity solely in a particular state.

Theoretically, separate accounting measures the net income of the business earned within the state. In practice it does not. The reason it does not stems from the way that large modern businesses, especially large integrated multinational corporations, operate.

The entire enterprise is operated as a unit with the profit being earned only by the entire operation as a whole. Thus the whole enterprise is actually more than the sum of the parts since each part is in being only to contribute to the entire unitary business. The net profit is actually the final result of the continuous series of income and expense transactions among the various component parts of the business. With regard to an integrated multinational oil corporation, the net income is not earned by any particular phase of the operation such as production, transportation, refining or marketing. Each segment contributes to the whole, and the net income is only reflected after the sale to the consumer and the contribution of each part of the business.

Because of the realities of modern business operations, a separate accounting method opens the doors to widespread tax avoidance. With a multifaceted business acting through different divisions, affiliates and subsidiaries, it doesn't matter to the overall enterprise whether a particular division is shown to make a profit or loss as long as in the end

a profit is made for the company as a whole. In a real sense the profit or loss of a particular division can be made to appear any way that the enterprise wants it to appear.

For example, when goods transferred as raw products from one division to another are produced and then transported to be refined and then transferred to market, the amount charged to each segment of the business can be anything that the enterprise finds in its best interest to charge. Likewise as the parent corporation or another division provides management, accounting, legal or other related services for another division or affiliate, the same flexibility exists for determining the amount of fees to be charged. Income and expense can be effectively shifted from one part of the business to another. This shifting of income and expense does not take place through a handful of easily recognizable transactions, but through a series of thousands of transactions a day which amount to millions for an entire year. Also, these transactions are made not just between a handful of corporate entities, but through literally hundreds of divisions, affiliates, and subsidiaries. With such a myriad of corporate entities and transactions, it is difficult, to say the least, to determine what is the "true" net profit earned by one entity or geographic part of an entity.

As Zeifman and Ainsworth observed about separate accounting:

COMPANIES WHICH USED SEPARATE ACCOUNTING IN 1973, 1974, AND 1975,  
THE TAXABLE INCOME ASSIGNED TO ALASKA BY THAT METHOD AND  
ALTERNATIVE METHODS WHENEVER POSSIBLE

|                    | <u>1973 TXBLE. INC.</u> | <u>1974 TXBL. INC.</u> |                | <u>1975 TXBL. INC.</u> |                |
|--------------------|-------------------------|------------------------|----------------|------------------------|----------------|
|                    | <u>Sep. Acctg.</u>      | <u>Sep. Acctg.</u>     | <u>Apport.</u> | <u>Sep. Acctg.</u>     | <u>Apport.</u> |
| A P.O.             | (4,688,123)             | (15,997,275)           |                | N.A.                   | 2,870,420      |
| Sub <sub>1</sub>   | 0                       | 0                      |                | N.A.                   | N.A.           |
| D Sub <sub>1</sub> | N.A.                    | N.A.                   |                | N.A.                   | N.A.           |
| E Sub <sub>1</sub> | N.A.                    | (2,294,094)            | (6,060,885)    | (23,721,209)           | N.A.           |
| H P.O.             | 0 <sup>1</sup>          | 0 <sup>1</sup>         |                | N.A.                   | (375,032)      |
| Sub <sub>1</sub>   | 0 <sup>1</sup>          | 0 <sup>1</sup>         |                | N.A.                   | (13,525,636)   |
| I P.O.             | 0 <sup>2</sup>          | 0 <sup>2</sup>         |                | 0 <sup>2</sup>         | N.A.           |
| J P.O.             | (1,829,201)             | (2,784,713)            |                | N.A.                   | 3,027,848      |
| K P.O.             | (1,979,609)             | (16,248,961)           |                | (12,748,645)           | 2,494,124      |
| Sub <sub>1</sub>   | (165)                   | (165)                  |                | (170)                  | N.A.           |

FOOTNOTES

P.O. - Parent corporation only.

1 - Not greater than zero for these cases.

2 - Known to be a negative amount.

COMPANIES WHICH USED SEPARATE ACCOUNTING IN 1973, 1974, AND 1975,  
THE TAXABLE INCOME ASSIGNED TO ALASKA BY THAT METHOD AND  
ALTERNATIVE METHODS WHENEVER POSSIBLE

|                    | <u>1973 TXBLE. INC.</u> | <u>1974 TXBL. INC.</u> |                | <u>1975 TXBL. INC.</u> |                |
|--------------------|-------------------------|------------------------|----------------|------------------------|----------------|
|                    | <u>Sep. Acctg.</u>      | <u>Sep. Acctg.</u>     | <u>Apport.</u> | <u>Sep. Acctg.</u>     | <u>Apport.</u> |
| A P.O.             | (4,688,123)             | (15,997,275)           |                | N.A.                   | 2,870,420      |
| Sub <sub>1</sub>   | 0                       | 0                      |                | N.A.                   | N.A.           |
| D Sub <sub>1</sub> | N.A.                    | N.A.                   |                | N.A.                   | N.A.           |
| E Sub <sub>1</sub> | N.A.                    | (2,294,094)            | (6,060,885)    | (23,721,209)           | N.A.           |
| H P.O.             | 0 <sup>1</sup>          | 0 <sup>1</sup>         |                | N.A.                   | (375,032)      |
| Sub <sub>1</sub>   | 0 <sup>1</sup>          | 0 <sup>1</sup>         |                | N.A.                   | (13,525,636)   |
| I P.O.             | 0 <sup>2</sup>          | 0 <sup>2</sup>         |                | 0 <sup>2</sup>         | N.A.           |
| J P.O.             | (1,829,201)             | (2,784,713)            |                | N.A.                   | 3,027,848      |
| K P.O.             | (1,979,609)             | (16,248,961)           |                | (12,748,645)           | 2,494,124      |
| Sub <sub>1</sub>   | (165)                   | (165)                  |                | (170)                  | N.A.           |

FOOTNOTES

P.O. - Parent corporation only.

1 - Not greater than zero for these cases.

2 - Known to be a negative amount.

With these negative taxable incomes assigned to Alaska, it is not surprising that major multinational corporations have vigorously lobbied several state legislatures and Congress for the authority to use separate accounting in the calculation of state income tax. As stated by Zeifman and Ainsworth in their report:

...a large lobby group of multi-national corporations known as COST (Committee on State Taxation) has been formed to press both the United State Congress and State Legislatures for legislation permitting them to use separate accounting techniques for State tax purposes. It is also noteworthy that COST is comprised of ninety-two of the one-hundred largest corporations in the United States and is both an advocate of separate accounting forms of taxation as well as an opponent of the joint audit program of the Multistate Tax Commission.  
[footnote omitted]

Additionally, increased auditing by the Department of Revenue is not an answer to what would be widespread tax avoidance by multinational corporations. Indeed, even the federal auditors are not able to police a separate accounting system. Again quoting from Zeifman and Ainsworth:

...proponents of separate accounting point out that the Department of Revenue would have the legal authority to recompute all of the transactions among all of the parties and their affiliates. However, for the Department of Revenue to do so would involve an extraordinarily complex series of cost-accounting types of audits of each affiliated service organization. Such audits would be similar to the complex audits used only rarely and as an extraordinary remedy by the Federal Government under Section 482 of the Internal Revenue Code.

On a Federal level, under Section 482, the Secretary of the Treasury has long had the power to re-allocate income and deductions among affiliated companies when "necessary in order to prevent evasion of taxes or clearly to reflect the income of any of such organizations." However, the difficulties of administering Section 482 has been found so great as to limit severely the usefulness of this power, even as an extraordinary remedy on a Federal level. Under the circumstances, since the problems posed by separate accounting on a State level are even more complex than on a Federal level, it is our opinion that individual states simply are not capable of developing sufficient audit capacity to rely on such extraordinary types of audits for the general enforcement of their tax programs. This is not only true with states such as Alaska, which has a comparatively small audit staff, but is also true with respect to such states as California, which has the largest and most experienced audit staff in the United States. [footnote omitted]

Thus, although separate accounting would theoretically present an accurate method of measuring net income earned in the state, in practice it presents taxpayers with the utmost in tax-avoidance possibilities.

Even if the problem of tax avoidance could be solved by ferreting out and overturning all corporate manipulations, separate accounting would still not work in Alaska's best interests. With potential depressed pricing of North Slope oil as described in Chapter V, the net income "earned in Alaska" by oil and gas corporations could be legitimately shown to be reduced while other unregulated segments of the business would be shown more profitable. The use of separate accounting would not take into account the relative value of the unrefined product to the rest of the business

or the contribution of the rest of the business to the portion of the income due to activity in Alaska. Separate accounting would look only to the one segment in isolation of the prices actually received.

## B. RECOMMENDATIONS FOR THE PRODUCTION TAX

### Effects on the economics of oil production operations.

The Department of Revenue recommends perfecting the "stair step" approach as a means of eliminating effects of the production tax on the economics of oil production operations. The key to doing so is not found by creating a series of "steps" and rates that succeed in this for any one area of the State, such as Cook Inlet. As explained in Chapter V, a well producing 1000 barrels a day may be quite a money maker in Cook Inlet but be mediocre or even marginal in other areas of the state such as the Interior or North Slope. Consequently the "stair steps" that succeed for the Inlet won't eliminate the economic effects of the tax elsewhere. Conversely, "stair steps" designed to eliminate those effects from production on the North Slope would give too much away to production in the Inlet.

To eliminate this difficulty, the Department of Revenue recommends an Economic Limit Factor (ELF), based on the ratio of the rate at the true economic limit to the current production rate, as a mechanism for scaling down the tax rate as the production declines toward the economic limit. This would be done by multiplying a basic tax rate times the difference between unity (the number, one) and the ratio of rate at the limit to current rate. As the following table illustrates, the ELF produces a smooth, continuous series

of tax rates, barrel by barrel, when applied to any basic tax rate, which scales the actual (effective) tax rate down to zero at the economic limit.

Scale Down of Effective Tax Rate  
by an Economic Limit Factor  
[ELF = 1 - Rate at Limit/Current Rate]  
(rate at limit = 200 B/D per well)

| Current Rate<br>(B/D per well) | Economic<br>Limit Factor | Effective<br>Tax Rate w/<br>an 8% Base | Effective<br>Tax Rate w/<br>a 10% Base | Effective<br>Tax Rate w/<br>a 12% Base |
|--------------------------------|--------------------------|----------------------------------------|----------------------------------------|----------------------------------------|
| 10,000                         | 0.9800                   | 7.84                                   | 9.80                                   | 11.76                                  |
| 8,000                          | 0.9750                   | 7.80                                   | 9.75                                   | 11.70                                  |
| 6,000                          | 0.9667                   | 7.73                                   | 9.67                                   | 11.60                                  |
| 5,000                          | 0.9600                   | 7.68                                   | 9.60                                   | 11.52                                  |
| 4,000                          | 0.9500                   | 7.60                                   | 9.50                                   | 11.40                                  |
| 3,000                          | 0.9333                   | 7.47                                   | 9.33                                   | 11.20                                  |
| 2,000                          | 0.9000                   | 7.20                                   | 9.00                                   | 10.80                                  |
| 1,500                          | 0.8667                   | 6.93                                   | 8.67                                   | 10.40                                  |
| 1,000                          | 0.8000                   | 6.40                                   | 8.00                                   | 9.60                                   |
| 800                            | 0.7500                   | 6.00                                   | 7.50                                   | 9.00                                   |
| 600                            | 0.6667                   | 5.33                                   | 6.67                                   | 8.00                                   |
| 500                            | 0.6000                   | 4.80                                   | 6.00                                   | 7.20                                   |
| 400                            | 0.5000                   | 4.00                                   | 5.00                                   | 6.00                                   |
| 350                            | 0.4286                   | 3.43                                   | 4.29                                   | 5.14                                   |
| 300                            | 0.3333                   | 2.67                                   | 3.33                                   | 4.00                                   |
| 250                            | 0.2000                   | 1.60                                   | 2.00                                   | 2.40                                   |
| 225                            | 0.1111                   | 0.89                                   | 1.11                                   | 1.33                                   |
| 200                            | 0.0000                   | 0.00                                   | 0.00                                   | 0.00                                   |

Notice how the effective tax rate does not begin to decline rapidly until production gets relatively close to the economic limit. In the table above with an assumed rate at the limit of 200 barrels a day per well, the effective rate is 98 percent of the base rate with 10,000 barrels-a-day wells. This percentage has merely dropped to 90 percent when the

well productivity is down to 2000 barrels a day. In other words, the ELF keeps the effective rate high while the current production rates are much larger than the economic limit rate, and thereby keeps the tax rate from scaling down too soon while the economics of the production operation remain quite sound. As the table shows, this is true regardless of what the base rate is.

On the other hand, the ELF really scales the rate down when the economic limit begins to get near. Thus, while the effective rate is 90 percent of the base rate at 2000 barrels a day in the table, it drops to 75 percent of the base rate at 800 barrels a day, to half of the base rate at 400, to one-fifth of the base rate at 250, and to zero at 200.

If the tax law conclusively sets the rate at the economic limit at some specific rate like 200 barrels a day per well, the ELF becomes simply one more economically rigid structure like the present "stair steps." It would not respond to the great regional differences in economic scale for production operations in Alaska. But the great advantage of the ELF over any specific set of "stair steps" is that it can be tied to the actual economic condition of a property anywhere in the state, thanks to using the ratio of production at the economic limit of that property to its current production rate.

The Department of Revenue recommends that the statute specify exactly how the Department should calculate the production rate at the economic limit. Basically, all that is involved in that calculation is finding out how many barrels of non-royalty oil it takes to have a total value in the field exactly equal to the total production costs for the property at the level of operations that will prevail at the economic limit. A rebuttable presumption should be created regarding the percentage by which the current level of operations would be cut back by the oil producer to a "bare bones" operation at the economic limit, which would put the burden on the taxpayer, instead of the Department, to come forward to support its position about what this percentage will be. The Department also recommends avoiding the difficulties of forecasting real or inflationary increases in oil prices and operating costs during the remaining economic life of the property; it proposes to do this by using the prevailing costs and world-market oil prices (netted back to the field) at the time it determines the production rate at the property's economic limit. It should be noted that with the ELF it is unnecessary to have more than one base rate for either the cents-per-barrel or the percent-of-value tax. Since the ELF already ensures a proper scaling down of the rate, multiple rates would only scale the tax down a second time, which would forfeit tax revenues that need not be foregone.

The Department also considered the possibility having a single rate for the cents-per-barrel tax and a single percentage for the percent-of-value tax using a type of "escape hatch" mechanism to scale the tax down after production reached some specified economic threshold near the true economic limit. It rejects this notion because the sudden tax benefits from crossing the threshold would create an incentive for a producer approaching that crucial point to hasten its arrival artificially.

Protecting State revenues from the effects of artificially low oil prices. As explained in Chapter II, the cents-per-barrel tax protects the State's production tax revenue by setting a "floor" for that revenue. If the price is set below a certain level, the cents-per-barrel tax becomes payable instead of the percent-of-value tax.

The Department of Revenue recommends raising the "floor" from its present level, which corresponds to \$6.10 a barrel for Prudhoe Bay oil, to a level more closely reflecting the full market value of that oil. At the present level of cents-per-barrel rates, the State's production tax income would have to suffer considerable reduction as the result of oil prices artificially lowered below the free-market price before the cents-per-barrel tax would begin working to prevent any further reduction.

To prevent the "floor" from losing value through time, it should escalate. The present escalator is the Wholesale Price Index for crude oil, but this Index reflects the aberrations of the present system of federal price controls. For example, the Index on occasion has changed solely as the result of a change in the estimated ratio of "old oil" to "new oil," when there was no change in domestic oil prices at all. The Department of Revenue recommends replacing the Index with the Gross National Product deflator, which would allow the "floor" to keep pace with nationwide inflation. Because world oil market prices may rise at a different rate than American inflation, it may be desirable to adopt an escalator that more closely follows world oil market conditions. The Department accordingly recommends using changes in the state sales price (exclusive of premiums and discounts for Saudi Arabian (31° API gravity) crude oil as the basis for escalating the cents-per-barrel tax.

The Department of Revenue also recommends modifying the cents-per-barrel tax so that it increases more and more as the price is further and further below the "floor" price that initially brings the cents-per-barrel tax into play instead of the percent-of-value tax. These increases would serve to offset in large part the State's cash royalties lost as the result of oil prices below the "floor" price.

To illustrate exactly what the Department's proposal

is, suppose the ELF recommendation is adopted, the single base rate for the percent-of-value tax is 10 percent, and the "floor" price is \$7.50. A statute incorporating the proposal would provide that the tax is 10 percent of the field price or 75 cents a barrel, whichever is greater. If the tax were payable on the cents-per-barrel basis, there would be an additional surtax equal to the final product of multiplying 11.42857 times the State's "Cash Royalty Fraction" times the tax difference between 75 cents per barrel and 10% of price. The "Cash Royalty Fraction" would be the number of barrels whose cash equivalent was paid to the State as royalty instead of being taken in kind, divided by the total number of barrels produced. This fraction naturally excludes State royalty oil taken in kind, and it would be zero when the State has no royalty interest at all in the production. The effect of this is to prevent the offsetting of "lost" royalty income when the State shouldn't be doing so, as when it doesn't own the land or when it sells royalty oil

If the ELF were incorporated into this proposal (and it should be incorporated), it should apply to the percent-of-value tax and to the 75 cents-per-barrel, but not to the surtax offsetting lost cash royalties. Not applying the ELF to the surtax creates an additional cost which advances the true economic limit; however, the agent causing the artificially low price can return the true economic limit

back to its original place by simply ceasing to manipulate the price and allowing it to rise to the full market value. Then the percent-of-value tax would take over, the surtax would no longer be paid, and the ELF that is applied to the percentage tax would keep the tax from advancing the true economic limit. In other words, the surtax provides an incentive to any would-be price manipulator to give the oil its fair (free market) price.

There may be a potential problem, however, with that portion of the recommendation regarding the "lost value" surtax. This would be due to the fact that there seems to be no way to avoid a direct reference to what we call the State's Cash Royalty Fraction. Without some such reference the surtax would apply to "lost" royalties for lands not owned by the State, where someone else will be the royalty owner. The surtax would also apply when the State's royalties were taken in kind, unless reference is made limiting it to the State's royalties taken in cash. This reference may engender a legal challenge to the surtax, and we recommend a review of this matter by the Attorney General.

In the event his review indicates that the surtax would be legally inadvisable, the Department of Revenue still would make its other recommendations to protect production tax revenues at least from artificially suppressed oil prices. Coupled with the ELF recommended in the preceding

section, this would assure the State of receiving fair production tax revenues despite any federal pricing actions or corporate profit-shifting activities, while simultaneously accommodating the case where a field or property is approaching its economic limit.

Protecting State revenues from the effects of artificially low gas prices. The Department of Revenue recommends an escalating "cents-per-Mcf" tax for gas, to be used in conjunction with the present percent-of-value tax. The percentage rate should rise to eight percent to achieve rate parity with oil, and the cents-per-Mcf rate should be six cents. The higher tax would be payable.

The Department would propose an ELF factor for the gas production tax, but because of the difference in the nature of production operations between oil and gas, the Department has not yet ascertained what an appropriate factor would be nor how it should be determined. As none of the major Cook Inlet area gas fields is anywhere close to reaching its economic limit, and since major production of gas for sale from Prudhoe Bay is still a number of years in the future, the Department recommends using some of this available time to pursue this subject further.

Flared gas. The Department of Revenue recommends that flared gas be taxed. Amending the statute to include flared

gas would do little good if percentage-of-value remains the sole basis for the gas production tax. The Department recommends a tax rate twice as high as the ordinary rage; if the Department's six cents per Mcf proposal above is adopted, this would mean 12 cents an Mcf for flared gas.

### C. RECOMMENDATIONS FOR THE PROPERTY TAX

As explained in Chapter V, there are four problem areas in the otherwise well functioning property tax: the omission of certain important kinds of oil and gas related properties from the definition of taxable property; present uncertainty about how pipelines should be valued; the static nature of the \$1500 per-capita limitation of municipal taxation; and the extent to which credits against the State tax should be allowed for municipal property tax payments.

The Uncertainty of Pipeline Valuation: As shown in Chapter V, the complex and confusing pipeline valuation portion of the property tax statute has led to litigations and uncertainty in the way that operating pipelines will be valued. In fact, there is even a chance that the depressed valuation method (depreciated-actual cost) might become the rule of valuation rather than the exception. Accordingly, the Department of Revenue recommends repealing the exception providing for a depreciated actual cost approach and retaining only the valuation method based on full and true value with due regard to economic value. If on further examination a better valuation method presents itself, the Department will recommend its substitution.

One alternative, which the Department is not recommending, would be to repeal both of the present valuation methods

and replace them with some specific appraisal technique (such as depreciated replacement cost) for ascertaining the full and true value of normal, operating pipelines. While this would establish one certain valuation method for all pipelines operating normally, its drawback is its foreclosure of applying other approaches (such as the income approach) which might better reflect full and true value in some circumstances.

As an alternative to repealing the exception, the Department does recommend amending that section of the statute to reflect clearly the Department's interpretation of it. The Department's interpretation is that if the present estimate of the economic life of the deliverable reserves is materially shorter than the owner's original expectation, then the exception applies and the pipeline will be valued on the basis of its actual cost with depreciation. Otherwise, it will be valued with due regard to its economic value.

This would insure that in most cases of normal operation of the pipeline, it would be valued on the basis of full and true value with due regard to economic value. It would still mean, however, that a determination would still have to be made as to when the actual economic life was "materially shorter" than the original expectations of the economic life and thus there would still be possibilities that the actual cost depreciated method would apply to normally

operating pipelines.

The Omission of Certain Kinds of Oil and Gas Related Properties From the Definition of Taxable Property. The Department of Revenue recommends expanding the definition of taxable property in the property tax statute to include oil refineries, gas processing plants, LNG facilities and petrochemical operations.

This will mean greater revenues to the State and will not materially affect the investment decisions of a prudent investor.

Recommendation to solve the static municipal limitations. The Department of Revenue recommends that the \$1500 per-capita limitation be tied to an escalator (such as the cost-of-living index) so that the municipal limitation will not lose value over time due to inflation. Thus the municipal limitation will increase as inflationary pressures increase the dollar cost to municipalities of maintaining services to its residents.

Recommendation for the municipal credit. The Department of Revenue recommends that the municipal credit section of the statute be amended to make absolutely clear that taxes paid to municipalities which exceed the limitations set out in AS 29.53.045 and AS 29.53.050 are not creditable

against the State tax, while also making clear that this limitation to the credit does not imply a limitation of the municipal power under AS 29.53.055 to exceed the "\$1500 per-capita" and "225 percent" limitations in the appropriate circumstances.

This will help assure that the municipal tax payments of only oil and gas property taxpayers are not subsidized in those circumstances, which would be the result of crediting the full payment against the State's property tax.

#### D. RECOMMENDATION FOR THE RESERVES TAX

Assuming that the Trans-Alaska Pipeline begins to transport oil as scheduled in July of this year, the Department of Revenue recommends that the reserves tax terminate on its scheduled expiration date of December 31, 1977.

CHAPTER VII. EFFECTS OF ADOPTING THE RECOMMENDATIONS

## A. REVENUE EFFECTS OF CORPORATE INCOME TAX RECOMMENDATIONS

As stated in Chapter VI, the Department makes two recommendations on the Corporate Income Tax. These recommendations are the adoption of a world-wide "book income" tax base, and the inclusion of a new apportionment factor based upon production. These recommendations essentially follow the proposals made by Zeifman and Ainsworth.

In their report, "The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax," Zeifman and Ainsworth discuss the revenue effects of the adoption of their proposals. With the adoption of a world-wide "book income" tax base and a three factor apportionment formula based upon property, payroll and extraction, they estimated a four-fold increase in corporate income tax revenues paid by oil and gas corporations. Specifically, for example, they found that their proposals would bring in an additional 10.9 million dollars in corporate income tax revenue for 1975. Since oil and gas corporate income taxes collected in 1975 were \$3.5 million dollars, the total corporate income tax revenues under the proposals would have been \$14.4 million dollars (slightly more than a four-fold increase).

The Department also analyzed the effect of the proposals in reference to the most recent year's corporate returns

and applied the same resulting percentage increase to the Department's projections of income tax revenues from oil and gas corporations in future years. Published figures of world-wide book incomes and production for the major oil and gas corporations in 1975 were used in computing the increase in 1975 revenues.

The Department projects corporate income tax revenues from major oil and gas companies under present law as follows:

Projections of Oil and Gas Corporate Income Tax  
Revenues Under Current Law  
(millions of dollars)

|      |    |
|------|----|
| 1978 | 46 |
| 1979 | 51 |
| 1980 | 54 |
| 1981 | 57 |
| 1982 | 60 |
| 1983 | 63 |
| 1984 | 66 |
| 1985 | 69 |

Using current data and extrapolating the potential current increases in tax into the future, the Department projects corporate income tax revenues under its recommendations as follows for major oil and gas companies: