HB

164

(FILE 1)

(SEE ALSO ELF)

MEMORANDUM

State of Alaska

TO: Honorable Steve Cowper
Governor

DATE: June 25, 1987

FILE NO:

TELEPHONE NO:

THRU:

SUBJECT: State of the Economy

FROM: J. Anthony Smith, Commissioner
Department of Commerce and
Economic Development

OFFICE OF
MANAGEMENT & BUDG
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STRATEGIC PLANN

INTRODUCTION

Over the past several weeks, I have met with many executives who are close to the state of Alaska's economy. Their reports, off the record, are grim

Dave Rose, Jim Sampson, Mark Hickey and I have discussed the short-range prospects for an economic upswing. Any near term economic projection bodes far worse than our public statements. While our diversification effort is promising over the longer run, we need to set in motion a short run program.

Action Plan

With this in mind, there are several measures which can be undertaken immediately.

Overall, we recommend you consider the implementation of a short-term economic stabilization program. Following are some specific actions the State of Alaska can take. This is not at variance with your statements that you don't need an Income Tax or ELF to balance the budget because it is a specific program. The goal is to complete projects which are required for infrastructure needs in the diversification effort, but were overlooked in the politics of "monument" building.

The following criteria for projects should be considered:

1. That there is a return to the State in jobs and in creation of opportunities to diversify.

STRATEGIC PLANNING
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OFFICE OF

2. The selected projects cannot create O&M requirements.

3. Select smaller projects so that there is not an incentive for outside companies to come in.

4. The emphasis should be on private sector, Alaska companies. It may be necessary to waive bond requirements as appropriate.

IMPLEMENTATION -- Short Term

1. The Legislature suspends ELF. This would result in increased revenues of $115 million for 1988 alone, according to figures from the Department of Revenue. These revenues are real capital that can be made available for projects that provide employment, create or improve infrastructure and allow the diversification program to be implemented. (For 1989 and 1990, increased revenues are estimated at $125 million and $135 million, respectively. These figures are based on the averages of projected oil prices.) The proposal is that the program would be such that the projects would linked to ELF.

2. We should canvass municipalities, boroughs, and State entities for status of all construction projects. For those projects already designed to specification and ready to build, we encourage notice to proceed be given to Alaskan architectural, engineering, and construction firms.

3. Through DOT/PF, set provisions in RFP's for state-wide projects to:

   a) Utilize Alaskan design and engineering firms, local labor, local companies,
   b) Select projects that are designed, permitted, and capable of being immediately let for bid;
   c) Utilize local labor, local companies, local supplies and materials and be of local or statewide benefit; and
   d) Select projects that can be administered by DOT/PF to insure that they facilitate economic diversification while we check the downward slide. However, force accounting should be avoided in construction projects.

4. Types of Projects Within the Scope of this proposal would include small Energy Projects, including small hydro-power such as was recently installed in Metlakatla and weatherization especially in rural locations. Other examples would be paving or road extension projects, and dock extensions/harbor improvements.

Mid-Term (one year out)

As you may be aware, Dave has proposed a Buy Alaska Campaign through Alaskan Permanent Fund dividend expenditures. If Alaskans spent their dividends in state, it is estimated there would be $400 million invested in Alaskan goods and services.

In addition, the Department of Adminsération and DCED should aggressively promote Made In Alaska and Alaskan contracts and import substitution.

We should continue our aggressive pursuit of Trade Alaska, venture capital possibilities, implementation of the new AIDA, and other attempts at economic diversification. In this context, Dave Rose is talking to his asset manager about long term capital investment.

In conclusion, through these immediate steps to stabilize our economy, we can utilize the State's resources to create wealth within Alaska for its citizens. It is my opinion that at this time we cannot justify ELF for Prudhoe. Therefore, we should use linkage to allow us to redirect the economy while we prevent the recession from becoming a depression.

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STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

March 25, 1988

The Honorable Mitch Abood
Chairman
Committee on State Affairs
Alaska State Senate
P.O. Box V
Juneau, AK 99811

Dear Mr. Chairman:

On March 2, 1988, I wrote you requesting an early hearing on CSHB 164, the "ELF bill." In your reply of March 10, 1988, you recited the oil industry's arguments against the bill, and concluded by stating that "for these reasons CSHB 164 dated April 15, 1987, will remain in the Senate State Affairs Committee."

There seems to be some confusion here. My request was for a hearing. That request, which I reiterate, reflects a firm belief that senators should have an opportunity to hear both sides of an issue before passing judgment on whether a bill will "remain in the Senate State Affairs Committee."

My administration looks forward to an early opportunity to present testimony on CSHB 164.

Sincerely yours,

Steve Cowper
Governor

OIL WATCH

Division of Policy
Office of the Governor

DATE: March 1, 1988

PREPARED BY: R.A. Fineberg

Spot Prices

The ANS Gulf Coast spot price dropped to $13.85-13.90 today. Over-supply and Saudi discounting again appear to be the principal factors in the latest price slump, which has driven the spot price down almost to its 12-month low (which occurred just before Christmas) and over $2.00 below the price at the beginning of the year.

The Department of Revenue estimates current North Slope production at 2.03 million barrels per day.

Attached are updated graphs showing spot, contract and posted prices. Since the last time we provided these graphs (Oil Watch, January 14, 1988), ANS Gulf spot and posted prices have levelled out in the $15 range. This makes $15 a reasonable basis for projecting contract prices in the near-term -- at least prior to last week's drop.

Effects on Mean Forecast for FY 88 and FY 89

A simplified model borrowed from the Department of Revenue indicates that if the ANS Gulf price holds at $15.00 for the remainder of the fiscal year, FY 88 revenues should be approximately $40 million below the $2,095 million mean forecast of Feb. 11.

If $15.00 held throughout FY 89, the February 11 mean forecast for FY 89 ($1,981 million) would be approximately $170 million high.[1]

Delphi Forecast

The forecast group will meet in Anchorage Monday and Tuesday, March 7-8. The completed forecast is expected early in April.

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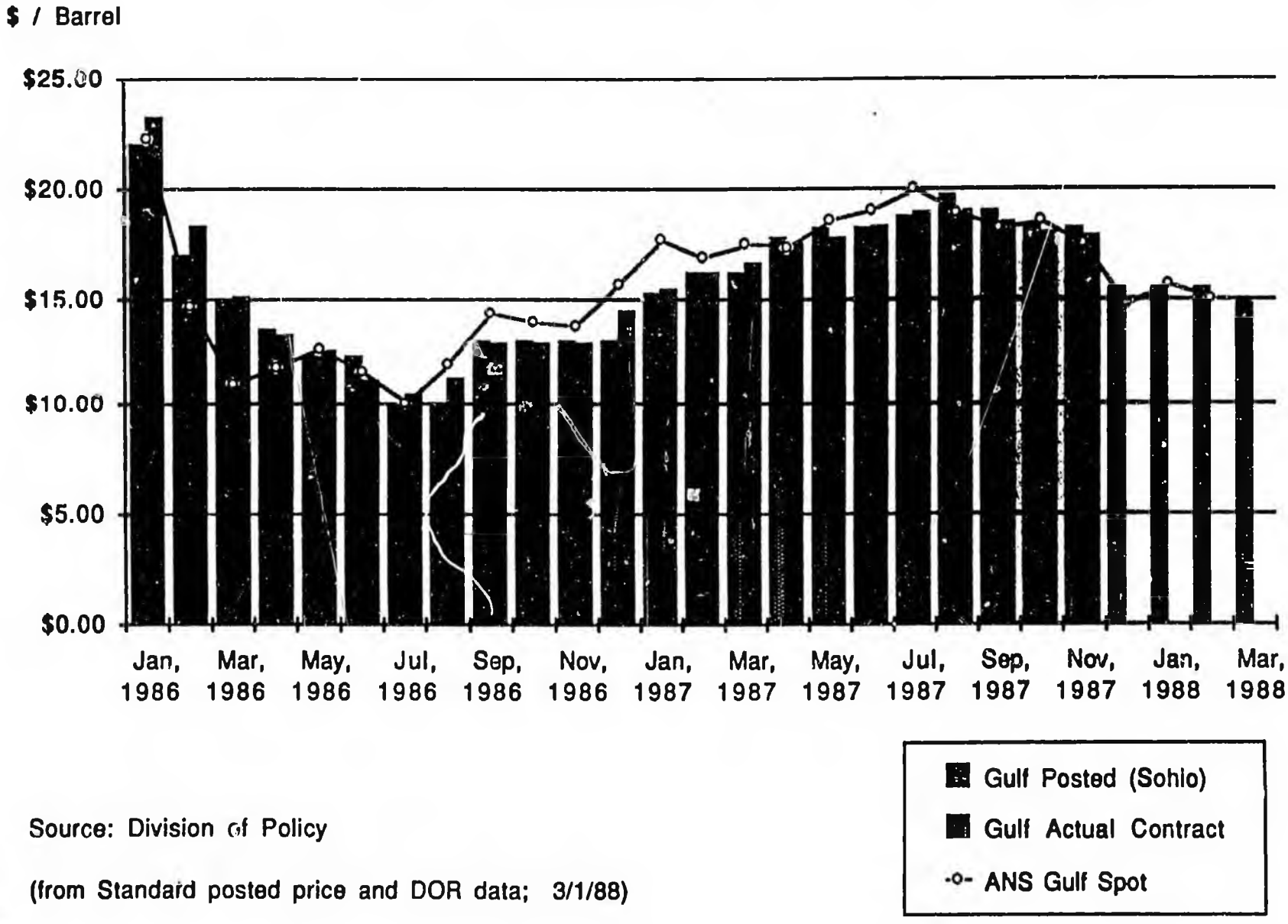
[1] The simple rule of thumb is that a $1.00 change in price over 12 months changes Unrestricted General Fund revenues by approximately $130 million. The FY 89 mean forecast price for ANS at the Gulf is $16.32. $1.32 x $130 = $172 million.

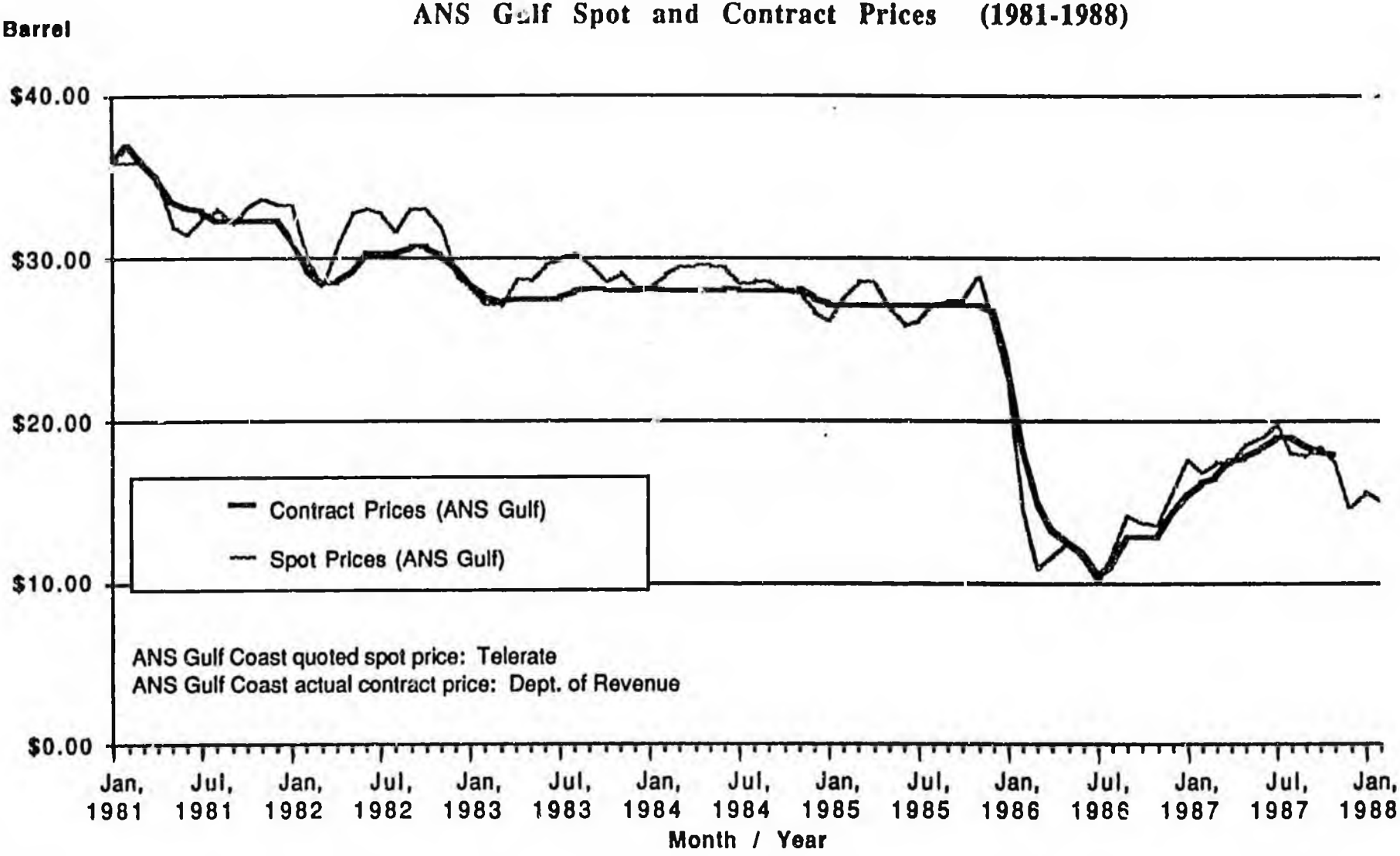
ANS Gulf Actual v. Spot & Posted Prices (1986-88)



Source: Division of Policy

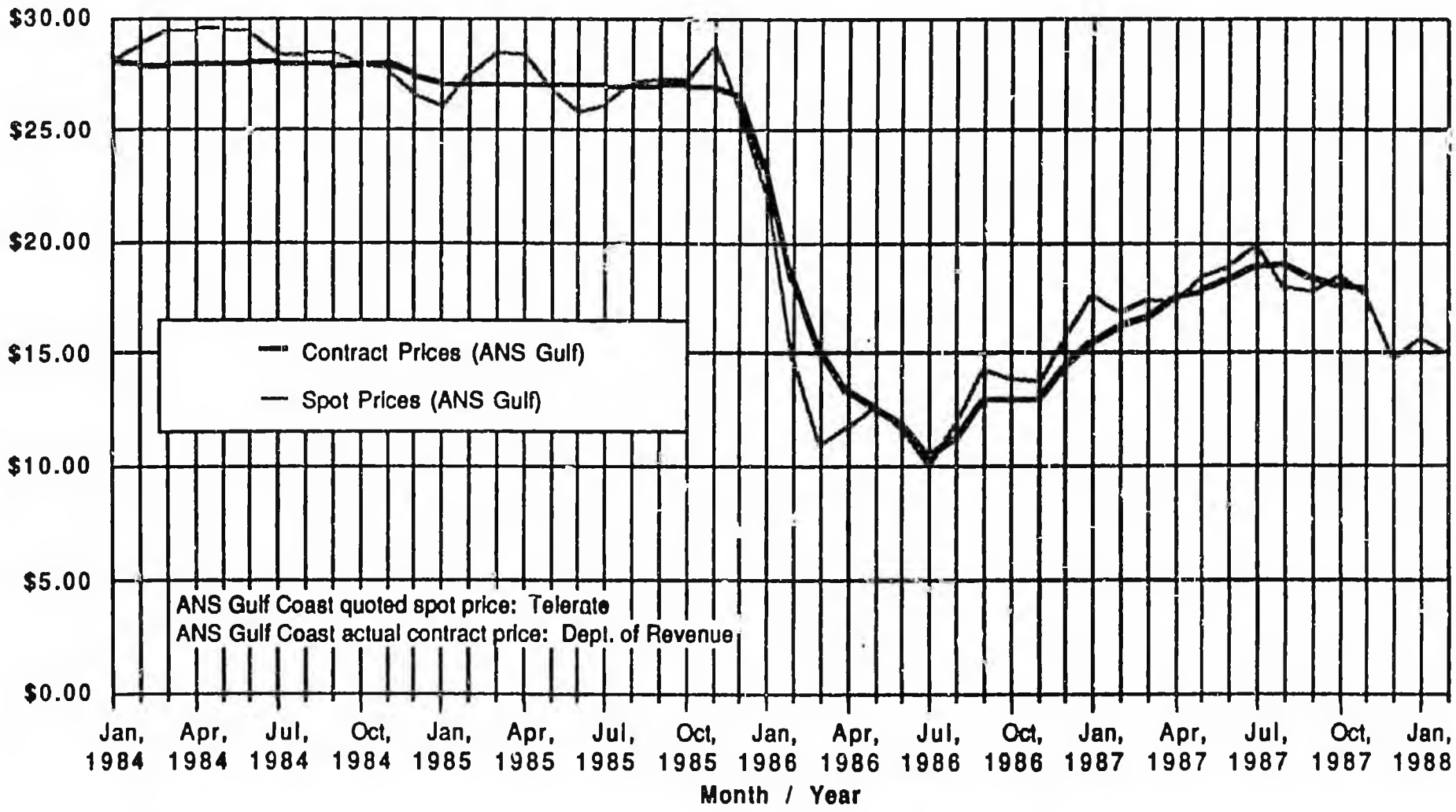
(from Standard posted price and DOR data; 3/1/88)

ANS Gulf Spot and Contract Prices (1981-1988)



Source: Division of Policy, 3/1/88

ANS Gulf Spot and Contract Prices (1984-1988)



Source: Division of Policy, 3/1/88

Distribution:

Governor Steve Cowper
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Natural Resources
Cameron Kashani, Legislative Finance

MEMORANDUM State of Alaska

TO: The Honorable Steve Cowper
Governor of Alaska

DATE: October 1, 1987

FILE NO:

TELEPHONE NO: 465-2173

THRU: Hugh Malone, Commissioner
Department of Revenue

SUBJECT: September Forecast

FROM: Vincent D. Wright
Chief of Research
Department of Revenue

The Department of Revenue has completed the September forecast and our assessment of the oil situation is basically the same as outlined in the June 5 memorandum to you on the subject. The numbers are somewhat higher, however, which is due to a combination of factors including (1) higher production assumptions stemming mainly from the Endicott field scheduled to come on stream shortly, (2) the fact that more revenue was generated than anticipated for the first quarter of FY 88, (3) adjustments in pipeline tariffs, (4) the Prudhoe Bay production decline curve being deferred until FY 90, and (5) the fact that this summer a premium price was paid for domestic crudes, including ANS, relative to OPEC crudes.

The market fundamentals suggest that oil prices will drop in the short-term given the excess supply of oil relative to the demand for oil, barring OPEC's ability to enforce its agreement of June 1987. The political abilities of OPEC to control market forces are, however, still very tenuous at this time.

The Economics

1. The inventory situation is such that crude oil stocks are as high as they were a year ago and increasing at this particular point in time.

2. The self-assuredness on the part of OPEC some months ago that their agreements would succeed in controlling world oil markets has in fact led to violation of output quotas and overproduction. The end result has been increased volatility and sagging oil prices. The OPEC countries to be sure are attempting to rectify this situation via jawboning member countries but it remains to be seen whether or not they will be successful.

3. The projected economic growth of the U.S. and other countries is anticipated to be sluggish. The affect will serve to dampen demand for petroleum related products.

4. The competition from alternative energy sources is still intense and will likely act to put a ceiling on any upward movement of oil prices in the future.

5. The refining industry in the U.S. and elsewhere is experiencing a squeeze on profit margins. The action of raising final product prices is limited by its negative effect on demand.

The conclusion we reached in June was that the "potential for oil prices faltering if not dropping is tremendous" and this indeed has already occurred.

The Politics

1. The incentives for the thirteen member OPEC group to hold together their agreement of June 1987 and even adjust it if necessary to insure success are fairly clear-cut. Most members are experiencing a negative cash flow situation and some are deeply indebted to other countries and the world banking system. Coupled with this is the fact that since 1982, with the drop in the price of oil, economic stagnation has plagued most of these countries. The political pressures from within these countries to rectify the situation are tremendous. But OPEC's struggle to succeed in holding together their June accord is fraught by divergent economic, religious, political, and financial interests.

2. In June we noted that Saudi Arabia had once again adopted the role of swing producer (i.e. agreed to adjust output below their allotted quota to make the OPEC agreement viable) but stated that this action would be temporary in light of their monetary situation. Since that time Saudi Arabia has announced it will no longer serve as swing producer for OPEC. The significance of this policy, if in fact it is adhered to, means that if other OPEC members violate their quotas, then there will be no one there to bail them out as has been the case in the past. Saudi Arabia, via this announcement, is attempting to push the other members into shouldering their responsibilities. In view of the history of OPEC member actions, this may be a futile effort on

the part of Saudi Arabia. The problem is that Saudi Arabia cannot afford, because of dwindling assets, to serve as swing producer indefinitely.

3. The Iran/Iraq war is a thorn in the side of all concerned. The Iraqis absolutely refuse to go along with their allotted output quota. Moreover, new pipelines in the process of being built are expected to provide additional Iraqi export capability. In view of the war effort and their indebtedness to the Saudi and Kuwait governments, Iraq has no choice but to go all out. It is literally a matter of survival.

   On the other hand if Iraq and Iran settle their war, production from these two countries could increase even more dramatically in an effort to rebuild their shattered economies.

4. I noted in the last forecast that "one of the major problems confronting OPEC, which Saudi Arabia and others recognize is the confidence on the part of some that the problem has been resolved and that OPEC is once again in control. Hence, some members are demanding that a higher official price be established. Others such as the UAE are demanding that their respective quotas be increased and if not, they will increase production regardless."

   Some of these countries did attempt to raise prices and have increased output and we have seen the results over the last forty-five days. OPEC is having a great deal of difficulty in keeping the situation under control. The responsible members of OPEC are cognizant of the fact that the current agreement is in jeopardy, and so what we see lately is a special OPEC committee designated to visit each member country with the idea of impressing upon them the necessity to refrain from violating the current accord.

   Off to the sidelines are the non-OPEC countries confronted by their own economic, political, and financial problems, closely watching and doubting OPEC's resolve. Many of these countries refuse to make further concessions to support the OPEC accord. Some have gone much further, to the chagrin of OPEC, and publicly announced they will go their own way if OPEC cannot adhere to its agreement. The end result, of course, would be to undermine any semblance of an OPEC accord.

The Conclusions

What does the above thumbnail sketch boil down to? It is quite obvious that there are few if any economic fundamentals suggesting that prices will increase and many reasons why they might decrease. The situation is one where OPEC actions, via delicate political maneuvering to control supply and demand, serve to bolster prices. And this is an area where the cohesiveness of OPEC, as alluded to above, is beset by problems.

What does this portend relative to oil prices? Will they increase? If OPEC can restrain individual members from engaging in widespread violations of the current agreement, if non-OPEC countries reaffirm their support, if worldwide demand for petroleum products remains positive, and if inventories are reduced, then prices should steady and perhaps increase next spring. The odds are increasing, however, that prices will drop further this winter as we indicated in June. The primary reason why prices have been holding lately is because of tensions in the Mid-East. The Achilies' heel to this, if there is one, is the fact that OPEC is taking advantage of this situation by pumping excessive quantities of oil, and at some point this action is surely going to have an adverse affect on prices. This means that prudence dictates a cautious approach relative to the State's spending plans.

The unrestricted revenue numbers are $1,728.2 million, $1,934.0 million, $1,784.6 million, and $1,925.4 million for FY 87, FY 88, FY 89, and FY 90 respectively. The changes, when compared to the June forecast, represent increases of $54.1 million, $217.9 million, and $112.5 million for FY 87, FY 88 and FY 89 respectively. The figure for FY 90 represents the introduction of a new year as is traditional during this time of the forecasting cycle.

The FY 87 number must be adjusted upward by $70.6 million for TAPs legal expenses and refunds. When this adjustment is made, the bottom line for FY 87 then amounts to $1,798.8 million This compares to a bottom line figure in June of $1,741.3 million.

Please note that the FY 87 number represents the preliminary actuals whereas the projected figures for FY 88, FY 89, and FY 90 represent the conservative 30% case.

I have attached for your perusal the details of this forecast along with the basic underlying assumptions, a short history of the State's revenue picture, and charts indicating the nominal versus real dollar outlook.

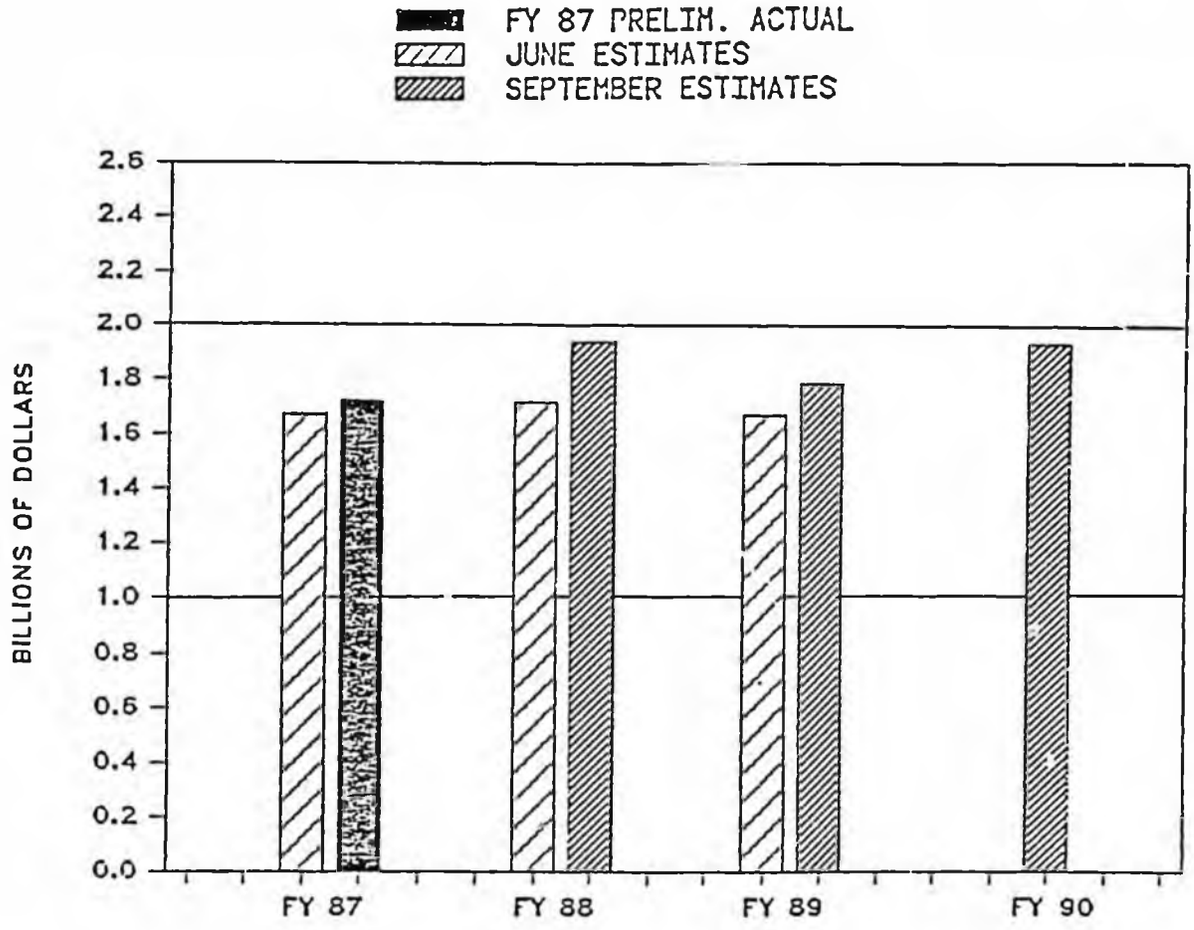
VDW:mkw

Attachment

FIGURE 1

GENERAL FUND UNRESTRICTED REVENUES

(COMPARISON OF PRIOR FORECASTS)



FY 87 Estimate/Prelim. Actual	
June 1987	1.6741 billion
September 1987	1.7282 billion
FY 88 Estimates	
June 1987	1.7161 billion
September 1987	1.9340 billion
FY 89 Estimates	
June 1987	1.6721 billion
September 1987	1.7846 billion
FY 90 Estimate	
September 1987	1.9254 billion

* IT SHOULD BE NOTED THAT ALL "SPECIAL SETTLEMENTS" HAVE BEEN EXCLUDED IN FY 87 IN ORDER TO BE CONSISTENT IN COMPARING PRIOR FORECASTS. THE FY 87 BOTTOM LINE WOULD INCLUDE AN ADDITIONAL $69.1 MILLION (TAPS REFUNDS/LEGAL EXPENSES) AND $1.5 MILLION (ARCO COURT COSTS).

TABLE I
General Fund Unrestricted Revenues
(Thousands of Current Dollars)

Taxes	FY 1987 Prelim. Actuals	FY 1988 Estimate September	FY 1989 Estimate September	FY 1990 Estimate September
Income				
Corporate-General	20,500	16,000	16,000	16,000
Corporate-Petroleum	120,400	120,000	120,000	120,000
Gross Receipts				
Alaska Business License	1,500	1,500	1,500	1,500
Fish-Canned/Shorebased (1)	17,500	6,000	7,000	9,000
Fish-Floating	9,000	9,800	9,800	9,800
Seafood Marketing	1,400	1,600	1,600	1,600
Salmon Enhancement	4,400	4,900	4,900	4,900
Insurance Companies	23,700	23,600	23,000	23,000
Electric & Telephone Co-ops	2,000	1,900	1,900	1,900
Mining License Tax	300	400	400	400
Severance				
Oil & Gas Production (2)	639,500	728,600	658,700	753,000
Oil & Gas Conservation (3)	1,200	2,500	2,500	2,600
Property				
Oil & Gas	102,500	75,000	67,000	60,000
Sale/Use				
Alcoholic Beverages	12,600	12,300	12,000	11,900
Fuel Taxes-Aviation (4)	8,500	8,300	8,200	8,200
Fuel Taxes-Highway (4)	18,300	19,000	18,700	18,700
Fuel Taxes-Marine (4)	5,400	5,000	5,000	5,000
Tobacco Products	6,600	6,300	6,100	6,000
Other				
Estate	1,100	700	700	700
Total Taxes	996,400	1,043,400	965,000	1,054,200
Licenses & Permits				
Business (5)	8,600	8,500	8,500	8,800
Non-Business	19,200	19,000	19,000	19,500
Total Licenses & Permits	27,800	27,500	27,500	28,300
Intergovernmental Receipts				
Federal Shared Revenues (6) (7)	11,700	9,500	9,800	10,000
State Resource Revenue				
Sale/Use				
Bonus Sales (6) (8) (9)	500	3,300	-0-	-0-
Investment Earnings (10)	161,900	115,000	90,000	60,000
Rents (6) (8) (9)	5,800	6,000	6,500	6,500
Royalties (2) (6)	445,100	654,700	608,800	688,200
Sale of State Property	7,000	7,500	7,500	7,500
Gravel, Timber, etc. (11).	7,200	2,500	2,500	2,500
Facilities Related Charges				
Airports	1,500	1,600	1,600	1,600
Ferry System-Southeast	27,500	29,000	31,000	32,000
Ferry System-Southwest	3,800	3,900	4,000	4,100
Other	4,000	5,000	5,000	5,000

Service Related Charges				
Court System	5,300	5,400	5,600	5,700
Other	4,700	4,700	4,800	4,800
Total State Resources Revenues	674,300	838,600	767,300	817,900
Miscellaneous Revenues	18,000	15,000	15,000	15,000
Unrestricted Revenues	1,728,200	1,934,000	1,784,600	1,925,400
Plus: Special Settlements (12)	70,600	-0-	-0-	-0-
Total Unrestricted Revenues (13)	1,798,800	1,934,000	1,784,600	1,925,400

(1) The FY 88, FY 89, and FY 90 figures reflect the recent enactment of a shorebased fisheries business tax credit which is limited to 50 percent of the business' total tax liability with any unused portion of the credit carried forward two years (Ch. 79, SLA 1986, effective July 1, 1986). For example, the total FY 88 fisheries business tax liability is estimated at $30.0 million against which $14.2 million of estimated credits are applied thus yielding a total net fisheries business tax of $15.8 million. This state share will then be further reduced by municipal revenue sharing. The canned fisheries business tax has been combined into a single category with the shorebased since the tax credits are applied against the aggregate return and cannot be allocated by specific processing type.

(2) The forecasted numbers for FY 88, FY 89, and FY 90 assume the 30 percent case; however, if the mean case had been utilized for FY 88, FY 89, and FY 90, the production taxes would change to $798.9 million, $764.9 million, and $857.1 million, respectively. The royalty figures would change to $715.7 million, $708.6 million, and $786.4 million, respecitvely. All of the forecasted numbers include the estimated TAPS settlement.

(3) Ch. 56, SLA 1987 increased the levy from 1.25 mills to 4.00 mills per barrel of oil and per 50,000 cubic feet of natural gas, effective June 13, 1987.

(4) In FY 86 and FY 87 the Department of Revenue began to levy marine fuel taxes on watercraft motor fuel users who purchased fuel out-of-state but consumed fuel in transit through the state. On March 30, 1987, the State adopted hearing decision #87-07 which established that marine fuel users who merely consumed fuel in transit could not be retroactively taxed. In line with this decision, the Department of Revenue has refunded with interest any taxes collected under the earlier interpretation. This forecast estimates that refunds plus interest will total $1.8 million and assumes that the majority of these refunds paid in FY 87. All motor fuel tax refunds are paid from the Highway Fuel Tax Account.

(5) Figures reflect the recent shift in occupational licensing fees and insurance permit fees from General Fund Unrestricted Revenues to Restricted Program Receipts.

(6) Net Permanent Fund contribution by Ch. 18 SLA 1980.

(7) The FY 87 figure reflects the CCS "8(g)" revenue-sharing settlement of $4.0 million. The General Fund share represents 49.5 percent of the aforementioned total, whereas the Permanent Fund will receive 50.0 percent. The remaining 0.5 percent will be distributed to the Public School Fund.

(8) Reflects state lease sales of $0.9 million held June 24, 1986 (Sale 49 - Cook Inlet), $0.3 million held January 27, 1987 (Sale 51 - Prudhoe Bay Uplands), and $6.6 million held June 30, 1987 (Sale 50 - Camden Bay). Due to the timing of collections, receipts from the June 1986 lease sale are shown as FY 87 revenue, and receipts from the June 1987 lease sale are shown as FY 88 revenue. The bonus figures represent the General Fund's 49.5 percent share.

(9) The Department of Natural Resources projects the following FY 88, FY 89, and FY 90 state lease sales: FY 88 (Sale 54 - Kuparuk Upland, Sale 55 - Demarcation Point, Sale 66A - North Slope Exempt); FY 89 (Sale 52 - Beaufort Sea, Sale 56 - Alaska Peninsula, Sale 67A - Cook Inlet Exempt); and FY 90 (Sale 59 - Cook Inlet, Sale 57 - North Slope Foothills). However, bonus bids are impossible to anticipate prior to sales; therefore, no estimates are provided.

(10) The investment earnings projections reflect the current composition of General Fund assets and current interest rates. The projections reflect a liquidation of General Fund assets over the period because projected General Fund cash expenditure outflows exceed projected General Fund cash revenue inflows. Cash inflows are consistent with the current revenue forecast. Cash outflows are consistent with the current FY 88 budget. General Fund operating expenditures were assumed to remain at approximately FY 88 levels through FY 90.

(11) The FY 87 figure reflects increased construction of roads and drilling pads as projected by the Department of Natural Resources.

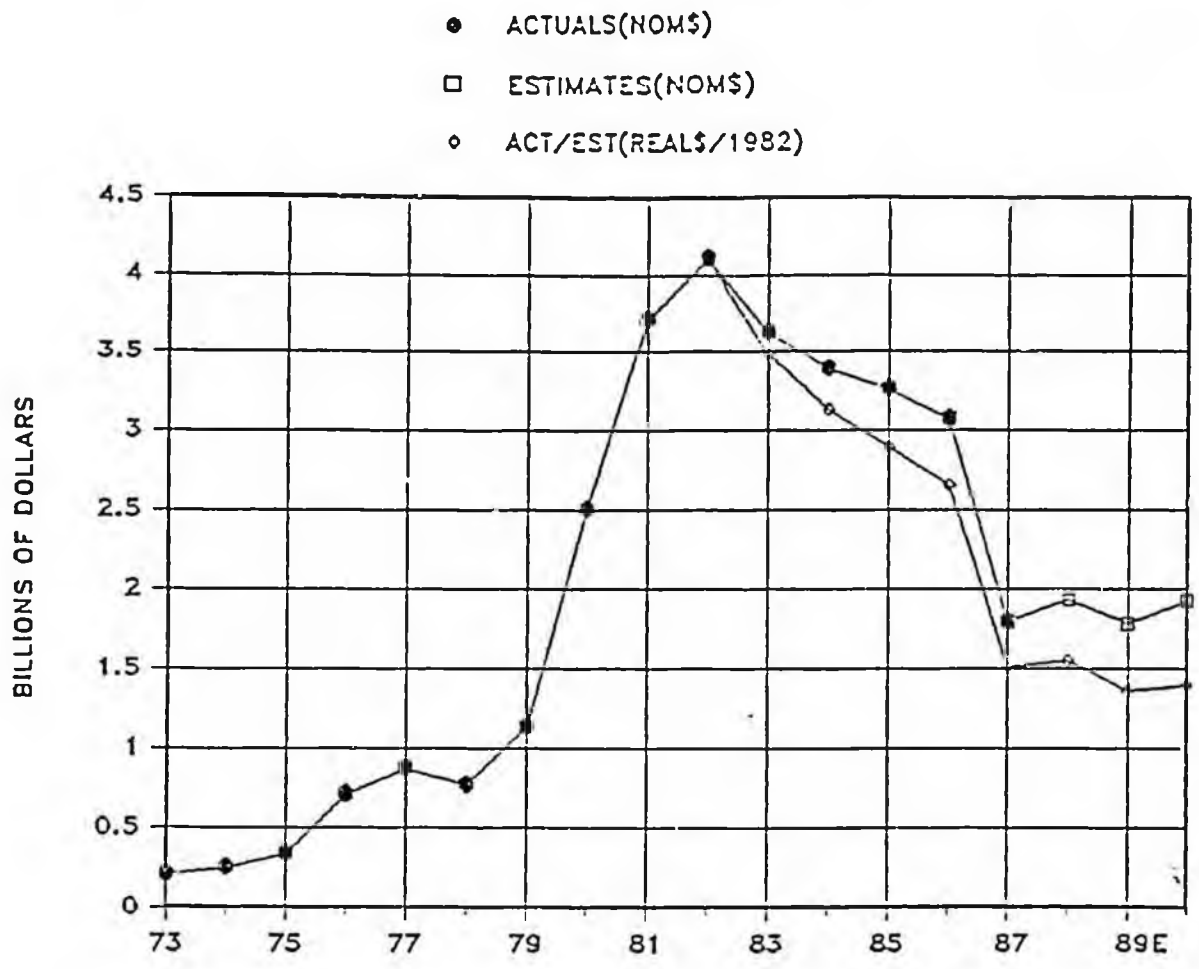
(12) The FY 87 figure reflects the General Fund portion from refunds and expenses for prior years relative to the TAPS case ($69.1 million) and court costs relative to the ARCO settlement ($1.5 million). Consequently, $70.6 million was received during FY 87, but this figure is subject to future audits.

(13) The State, per AS 38.05.180, will be granting incentive credits against royalties, severance taxes, and rentals to the oil companies for drilling exploratory wells. The deduction is approximately $2.9 million which has not been subtracted from the aforementioned FY 87 figure of $1,796.8 million. Additional credits are anticipated in subsequent years.

FIGURE 2

GENERAL FUND UNRESTRICTED REVENUES

(NOMINAL DOLLARS VS. REAL DOLLARS)



Revenue Actuals (Nominal $)	
FY 73	.2082 billion
FY 74	.2549 billion
FY 75	.3334 billion
FY 76	.7098 billion
FY 77	.8743 billion
FY 78	.7649 billion
FY 79	1.1330 billion
FY 80	2.5012 billion
FY 81	3.7182 billion
FY 82	4.1084 billion
FY 83	3.6310 billion
FY 84	3.3901 billion
FY 85	3.2600 billion
FY 86	3.0755 billion
FY 87*	1.7988 billion

Revenue Estimates (Nominal $)	
FY 88	1.9340 billion
FY 89	1.7846 billion
FY 90	1.9254 billion

Revenue Actuals/Estimates (Real $/1982)	
FY 82	4.1084 billion
FY 83	3.4826 billion
FY 84	3.1347 billion
FY 85	2.9002 billion
FY 86	2.6584 billion
FY 87	1.5096 billion
FY 88	1.5560 billion
FY 89	1.3681 billion
FY 90	1.4019 billion

* Preliminary

TABLE II

Key Assumptions for September 1987
Petroleum Revenue Projections
For FY 1987 - FY 1990

Fiscal Year	($/bbl) Mean Wellhead Value	($/bbl) 30% Wellhead Value	Mean TAPS Throughput (MMbbs/day)	Mean Rate Inflation %
1987	$7.35	$7.35	1.858	3.02
1988	$11.11	$10.17	1.903	4.32
1989	$10.74	$9.25	1.949	4.92
1990	$12.05	$10.57	1.929	5.45

Sales Price for
Alaska North Slope Crude Oil at Los Angeles, California

	Weighted Average	30% Case	
FY 87	$13.42	$13.42	per barrel
FY 88	$15.98	$15.04	per barrel
FY 89	$15.16	$13.67	per barrel
FY 90	$15.90	$14.42	per barrel

Sales Price for
Alaska North Slope Crude Oil at Houston, Texas

	Weighted Average	30% Case	
FY 87	$14.70	$14.70	per barrel
FY 88	$17.16	$16.22	per barrel
FY 89	$16.32	$14.83	per barrel
FY 90	$17.08	$15.60	per barrel

Weighted Average TAPS Tariff

FY 87	$4.25	per barrel
FY 88	$3.52	per barrel
FY 89	$2.69	per barrel
FY 90	$2.66	per barrel

MEMORANDUM State of Alaska

TO: The Honorable Steve Cowper
Governor of Alaska

DATE: June 5, 1987

FILE NO.:

THRU: Hugh Malone, Commissioner
Department of Revenue

TELEPHONE NO.: 465-2173

SUBJECT: June Revenue Forecast

FROM: Vincent D. Wright
Chief of Research
Department of Revenue

The Department of Revenue, per your instructions, has put together the unrestricted revenue forecast approximately one month earlier than is normally the case. You should be aware that by moving up the schedule we have not had the benefit of evaluating key information such as economic and tax data normally available, seasonal factor trends, nor the results from the OPEC meeting scheduled for the latter part of June.

There has been a great deal of speculation recently that oil prices will continue to improve and the State's revenue position in corresponding fashion. This may very well be true. However, there are factors that still suggest tremendous downside risk relative to oil prices and I will touch on some of these in this letter.

The fundamentals of supply and demand do not support current oil prices. The underlying reason for relatively high oil prices is a political solution (i.e. the OPEC agreement established during December of 1986) which is still very tenuous at this time. The reasons for this are outlined below and it is crucial that the decision makers recognize these facts and adjust their thinking relative to expected revenues accordingly.

The Economics

1. Oil prices are relatively high because OPEC has restricted production and partly because refiners worldwide have been purchasing oil in vast quantities in anticipation of still higher prices. So what we have are very large inventories on hand. Unleaded gasoline stocks in this country alone are 30% higher than a year ago. Crude stocks in the U.S. are fairly close to their levels of last year and worldwide they are considerably higher than a year ago.

2. The value of the dollar has declined in the last 24 months relative to Japanese and some European currencies. Since OPEC oil is pegged in terms of the dollar, it has been relatively cheap and so this too has served as a stimulant to overseas refiners to purchase and thus build large stocks of crude.

3. The increasing self-assuredness on the part of OPEC that their December 1986 agreement has succeeded in controlling world oil markets is now leading to overproduction. Their second quarter quota is 15.8 million barrels per day but they are now producing between 16.5 to 17 million barrels per day. Saudi Arabia is becoming worried about the increasing tendency on the part of some OPEC members to step-up their cheating.

4. Higher levels of inflation are occurring. Last year the Consumer Price Index (CPI) was 1.9%. Now inflation is running between three and four percent and is projected by many to continue to climb. Higher inflation means higher interest rates which in turn means higher costs in storing oil. At some point this could lead to a divestiture of oil inventories. Hence, dumping of crude on world markets could occur.

5. The projected economic growth of the U.S. and other countries is sluggish at best. Worldwide GDP growth for non-communist countries is expected to run 2.5% next year. Thus, the demand for petroleum related products will be affected.

6. Alternative energy sources such as natural gas, of which large reserves exist around the world to operate utility and industrial plants, are currently on a btu parity value with various crudes. During those earlier years (the late 70's and early 80's) of relatively high oil prices, many existing utility and industrial users retrofitted to handle alternative fuels like natural gas. Further, newer plants built during the last few years have concentrated on diversifing so as to be able to burn alternative sources of energy should oil prices once again soar. The point is that competition from substitute fuels is more intense than ever and will likely act to restrain the upward movement of oil prices in the future.

7. Historically, demand for oil in this country has dropped and for the last several years to the tune of approximately 1 million barrels per day during the summer months. This same phenomena occurs throughout the rest of the world as well. The primary reason for this is destocking due to less heating oil usage. Since this has happened almost every year for over a quarter of a century, there is no reason to anticipate that the situation will change. The drop in demand for oil due to seasonal factors is just around the corner.

8. Refiners in the U.S. and elsewhere are now experiencing a squeeze on refinery or profit margins i.e. crude costs are going up relative to the price of the finished product. Refiners would like to raise product prices to cover their costs. But over time higher prices will act as a damper on demand.

In conjunction with the problem just mentioned is the fact that the OPEC quota of 15.8 million barrels per day does not apply to OPEC refinery operations of which there are a growing number. Hence, an increase in the output of refined products is taking place. This means more competition which should theoretically lead to lower prices for the finished product. This in turn translates into less demand for crude which means downward pressure on prices.

If arguments one through eight are considered as a whole, then the potential for oil prices faltering if not dropping is tremendous.

The Politics

1. The incentives for the thirteen member OPEC group to hold together their agreement of December 21, 1986 and even adjust it if necessary to insure success are fairly clear-cut. All members are experiencing a negative cash flow situation and some are deeply indebted to the other countries and the world banking system. Coupled with this is the fact that since 1982, with the drop in the price of oil, economic stagnation has plagued most of these countries. The political pressures from within these countries to rectify the situation are tremendous. But OPEC's struggle to succeed in holding together their December accord is fraught by divergent economic, religious, political and financial interests.

2. The Saudis have once again adopted the role of swing producer (i.e. adjusted output below their 4.1 million barrel per day quota in order to make the OPEC agreement viable) but we believe this is only temporary in light of their monetary situation. In fact, as I write this, the latest data available suggests that Saudi Arabia is producing at or close to their quota of 4.1 million barrels per day. They currently have the capability to produce more than twice this amount. The Saudis' projected deficit this year is expected to be $15 billion and they are rapidly drawing down their liquid assets. Their resolve to hold the line is there but they do not have the resources to continue much longer. More production cuts may be necessary if OPEC is to maintain its current price structure, but the economic realities may limit Saudi Arabia's ability to play the key role that it has in the past. And it must be kept in mind that Saudi Arabia is the only member of OPEC who has consistently assumed this responsibility in the past.

   The irony of this whole thing is that Saudi Arabia with its vast reserves (publicly known proven reserves are in excess of 167 billion barrels of oil) of low cost oil has the ability to flood world markets thus forcing out higher cost competitors in the process. The end result would be plunging oil prices but the Saudi's revenues would increase. Holding them in check at this stage of the game is the threat of aggression on the part of some of their neighbors who would be severely damaged economically, financially, and politically if the Saudis were to initiate such a plan.

3. The Iran/Iraq war is a thorn in the side of all concerned. The Iraqis absolutely refuse to go along with their allotted quota of 1.466 million barrels per day and are currently producing between 1.8 and 2 million barrels per day. This excludes production from the Saudi and Kuwaiti Neutral Zone which is utilized to finance the Iraq war. Moreover, a new pipeline from the northern part of the country across Turkey to the Mediterranean Sea is scheduled for completion this winter and will add an additional 500,000 barrels a day to Iraq's export capacity. Iraq also plans to build a second line to the Red Sea port of Yanbu in addition to the one just completed. This new line is expected to pump an additional 1.6 million barrels per day, 18 months from now. In view of the war effort and their indebtedness to the Saudi and Kuwait governments, Iraq has no choice but to go all out. It is literally a matter of survival.

   On the other hand if Iraq and Iran settle their war, production from these two countries could increase even more dramatically in an effort to rebuild their shattered economies.

4. After countless discussions over an extended period of time, OPEC has persuaded many non-OPEC countries that it is to their benefit to assist in the overall effort to control oil markets. Hence, the Soviet Union, Egypt, Norway, Mexico and others have contributed in some form or fashion but this support is wavering. And for some countries such as Mexico with large excess oil producing capacity and on the verge of financial collapse, except for the aid of the international banking system, the situation is highly intolerable.

5. The next OPEC meeting scheduled for the latter part of June will be a test to see if the current OPEC agreement survives. One of the major problems confronting OPEC, which Saudi Arabia and others recognize, is the confidence on the part of some that the problem has been resolved and that OPEC is once again in control. Hence, some members are demanding that a higher official price be established. Others such as the UAE are demanding that their respective quotas be increased and if not, they will increase production regardless. The UAE is one of those OPEC members that has been a chronic cheater this last year. Although third quarter OPEC quotas are scheduled to increase to 16.6 million barrels per day, the fundamentals of supply and demand do not support the current agreement let alone the additional demands of member countries or the increased production scheduled shortly to come on-line. Hence, in the last few weeks we have observed the more responsible members of OPEC attempting to prevail upon those less responsible to stay with the current agreement. The responsible members of OPEC are cognizant of the fact that the current agreement could come completly unraveled, and to ask for more is pushing the whole situation to the brink where once again the specter of plunging oil prices could become a reality.

Off to the sidelines are the non-OPEC countries confronted by their own economic, political, and financial problems, closely watching and doubting OPEC's resolve. Many of these countries refuse to make further concessions and are waiting to decipher the results of the next OPEC meeting. Even then, assuming a favorable OPEC accord, some of these countries might quietly seize the opportunity to move in and take advantage of the situation as they have so often in the past and abandon their own agreements with OPEC. The end result, of course, would be to undermine any OPEC accord.

The Conclusions

What does the above thumbnail sketch boil down to? It is quite obvious that there are few if any economic fundamentals suggesting that prices will continue to increase and many reasons why they might decrease. The situation is one where OPEC actions, via delicate political maneuvering to control supply and demand, serve to bolster prices. And this is an area where the cohesiveness of OPEC, as alluded to above, is beset by problems.

What does this portend relative to oil prices? Will they increase? If OPEC can restrain individual members from engaging in widespread violations of the current agreement, if non-OPEC countries continue to offer both tacit and overt support, if worldwide demand for petroleum products does not reverse itself, and if inventories are reduced throughout the summer, then prices should steady and perhaps increase next winter. But the professional traders who put their money on the line are betting that prices will drop this winter as is evident by trading in the futures market. This means that prudence dictates a cautious approach relative to the State's spending plans.

Having considered the aforementioned economic and political factors, plus pro and con arguments that I will not elaborate on here, and using what available data we have acquired since the last forecast to run through our computer models, the results of our analysis are outlined below.

The updated unrestricted revenue numbers are $1,674.1 million, $1,716.1 million, and $1,672.1 million for FY 87, FY 88, and FY 89 respectively. The changes, when compared to the March forecast, represent increases of $75.7 million, $183.5 million, and $82.4 million for FY 87, FY 88 and FY 89 respectively.

The FY 87 number must be adjusted upward by $67.2 million for TAPS legal expenses and refunds. When this adjustment is made, the bottom line for FY 87 then amounts to $1,741.3 million.

Please note that the FY 87 number represents the mean case whereas the figures for FY 88 and FY 89 represent the more conservative 30% case.

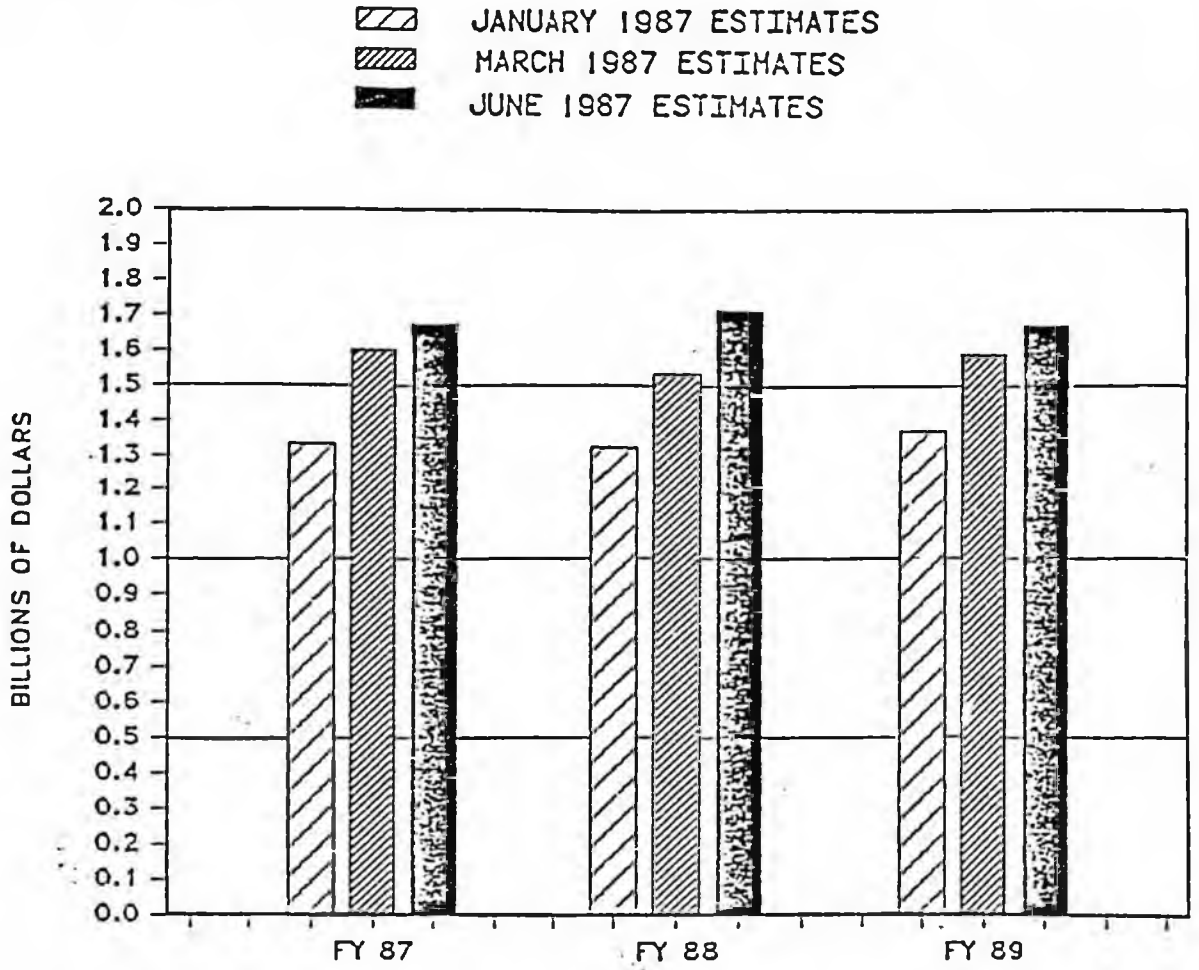
I have attached for your perusal the details of this forecast along with the basic underlying assumptions, a short history of the State's revenue picture, and charts indicating the nominal versus real dollar outlook.

VDW:mkw

FIGURE 1

GENERAL FUND UNRESTRICTED REVENUES

(COMPARISON OF PRIOR FORECASTS)



FY 87 Estimates	
January 1987	1.3342 billion
March 1987	1.5984 billion
June 1987	1.6741 billion
FY 88 Estimates	
January 1987	1.3250 billion
March 1987	1.5326 billion
June 1987	1.7161 billion
FY 89 Estimates	
January 1987	1.3739 billion
March 1987	1.5897 billion
June 1987	1.6721 billion

* IT SHOULD BE NOTED THAT ALL "SPECIAL SETTLEMENTS" HAVE BEEN EXCLUDED IN FY 87 IN ORDER TO BE CONSISTENT IN COMPARING PRIOR FORECASTS. THE FY 87 BOTTOM LINE WOULD INCLUDE AN ADDITIONAL $65.7 MILLION (TAPS REFUNDS/LEGAL EXPENSES) AND $1.5 MILLION (ARCO COURT COSTS).

TABLE I
General Fund Unrestricted Revenues
(Thousands of Current Dollars)

Taxes	FY 1987 Estimate June	FY 1988 Estimate June	FY 1989 Estimate June
Income			
Corporate-General	14,000	15,000	15,500
Corporate-Petroleum	95,000	110,000	110,000
Gross Receipts			
Alaska Business License	2,000	2,000	2,000
Fish-Canned/Shorebased (1)	16,600	8,800	8,800
Fish-Floating	9,000	8,000	8,000
Seafood Marketing	1,400	1,200	1,200
Salmon Enhancement	4,200	3,800	3,800
Insurance Companies	23,600	22,000	21,000
Electric & Telephone Co-ops	1,900	1,900	1,900
Mining License Tax	300	400	400
Severance			
Oil & Gas Production (2)	624,300	637,900	630,400
Oil & Gas Conservation	800	700	700
Property			
Oil & Gas	109,000	80,000	71,000
Sale/Use			
Alcoholic Beverages	12,800	12,300	12,000
Fuel Taxes-Aviation (3)	8,100	7,800	7,700
Fuel Taxes-Highway (3)	17,500	18,900	18,700
Fuel Taxes-Marine (3)	5,000	4,700	4,600
Tobacco Products	6,600	6,400	6,300
Other			
Estate	1,100	700	700
Total Taxes	953,200	942,500	924,700
Licenses & Permits			
Business (4)	9,500	9,800	9,800
Non-business	20,000	21,000	21,000
Total Licenses & Permits	29,500	30,800	30,800
Intergovernmental Receipts			
Federal Shared Revenues (5)	8,800	8,500	8,500
State Resource Revenue			
Sale/Use			
Bonus Sales (5) (6) (7) (8)	2,500	-0-	-0-
Investment Earnings (9)	160,000	100,000	65,000
Rents (5) (6) (7) (8)	5,500	6,000	6,500
Royalties (2) (5)	437,900	556,200	562,900
Sale of State Property	8,000	9,000	9,000
Gravel, Timber, etc. (10)	8,000	2,500	2,500
Facilities Related Charges			
Airports	1,600	1,600	1,600
Ferry System-Southeast	29,000	30,000	31,200
Ferry System-Southwest	3,800	3,900	4,000
Other	5,000	5,000	5,000

Service Related Charges			
Court System	5,300	5,400	5,600
Other	6,000	4,700	4,800
Total State Resources Revenues	672,600	724,300	698,100
Miscellaneous Revenues	10,000	10,000	10,000
Unrestricted Revenues	1,674,100	1,716,100	1,672,100
Plus: Special Settlements (11)	67,200	-0-	-0-
Total Unrestricted Revenues (12)	1,741,300	1,716,100	1,672,100

(1) The FY 88 and FY 89 figures reflect the recent enactment of a shorebased fisheries business tax credit per Ch. 79, SLA 1986, effective July 1, 1986. The canned fisheries business tax has been combined into a single category with the shorebased since the tax credits are applied against the aggregate return and cannot be allocated by specific processing type.

(2) The FY 87 forecast assumes the mean case. The forecasted numbers for FY 88 and FY 89 assume the 30 percent case; however, if the mean case had been utilized for FY 88 and FY 89, the production taxes would change to $717.9 million and $732.3 million, respectively. The royalty figures would change to $626.3 million and $666.8 million respectively. All of the forecasted numbers include the estimated TAPS settlement.

(3) In FY 86 and FY 87 the Department of Revenue began to levy marine fuel taxes on watercraft motor fuel users who purchased fuel out-of-state but consumed fuel in transit through the state. On March 30, 1987, the State adopted hearing decision #87-07 which established that marine fuel users who merely consumed fuel in transit could not be retroactively taxed. In line with this decision, the Department of Revenue is refunding with interest any taxes collected under the earlier interpretation. This forecast estimates that refunds plus interest will total $1.8 million and assumes that the majority of these refunds will be paid in FY 87. All motor fuel tax refunds are paid from the Highway Fuel Tax Account.

(4) Figures reflect the recent shift in occupational licensing fees and insurance permit fees from General Fund Unrestricted Revenues to Restricted Program Receipts.

(5) Net Permanent Fund contribution by Ch. 18 SLA 1980.

(6) Reflects state lease sales of $0.9 million held June 24, 1986 (Sale 49 - Cook Inlet), and $0.3 million held January 27, 1987 (Sale 51 - Prudhoe Bay Uplands). Due to the timing of collections, receipts from the June 1986 lease sale are shown as FY 87 revenue. The bonus figures represent the General Fund's 49.5 percent share.

(7) The FY 87 figure reflects the OCS "8(g)" revenue-sharing settlement of $4.0 million. The General Fund share represents 49.5 percent of the aforementioned total, whereas the Permanent Fund will receive 50.0 percent. The remaining 0.5 percent will be distributed to the Public School Fund.

(8) The Department of Natural Resources projects the following FY 87, FY 88, and FY 89 state lease sales: FY 87 (Sale 50 - Camden Bay); FY 88 (Sale 54 - Kuparuk Upland, Sale 55 - Demarcation Point); and FY 89 (Sale 52 - Beaufort Sea, Sale 56 - Alaska Peninsula). However, bonus bids are impossible to anticipate prior to sales; therefore, no estimates are provided.

(9) The investment earning projections presented reflect the current composition of General Fund assets and current interest rates. The projections also reflect a drawdown in the level of the General Fund assets over the projection period. The projected drawdown in assets is a result of projected revenue cash inflows consistent with the current revenue forecast and projected expenditure cash outflows consistent with the estimated FY 88 operating budget which was passed by the Legislature before any gubernatorial vetoes. Also, no capital budget appropriations for FY 88 were factored into the expenditure cash outflow projection because no capital budget was passed by the Legislature.

(10) The FY 87 estimate reflects increased construction of roads and drilling pads as projected by the Department of Natural Resources.

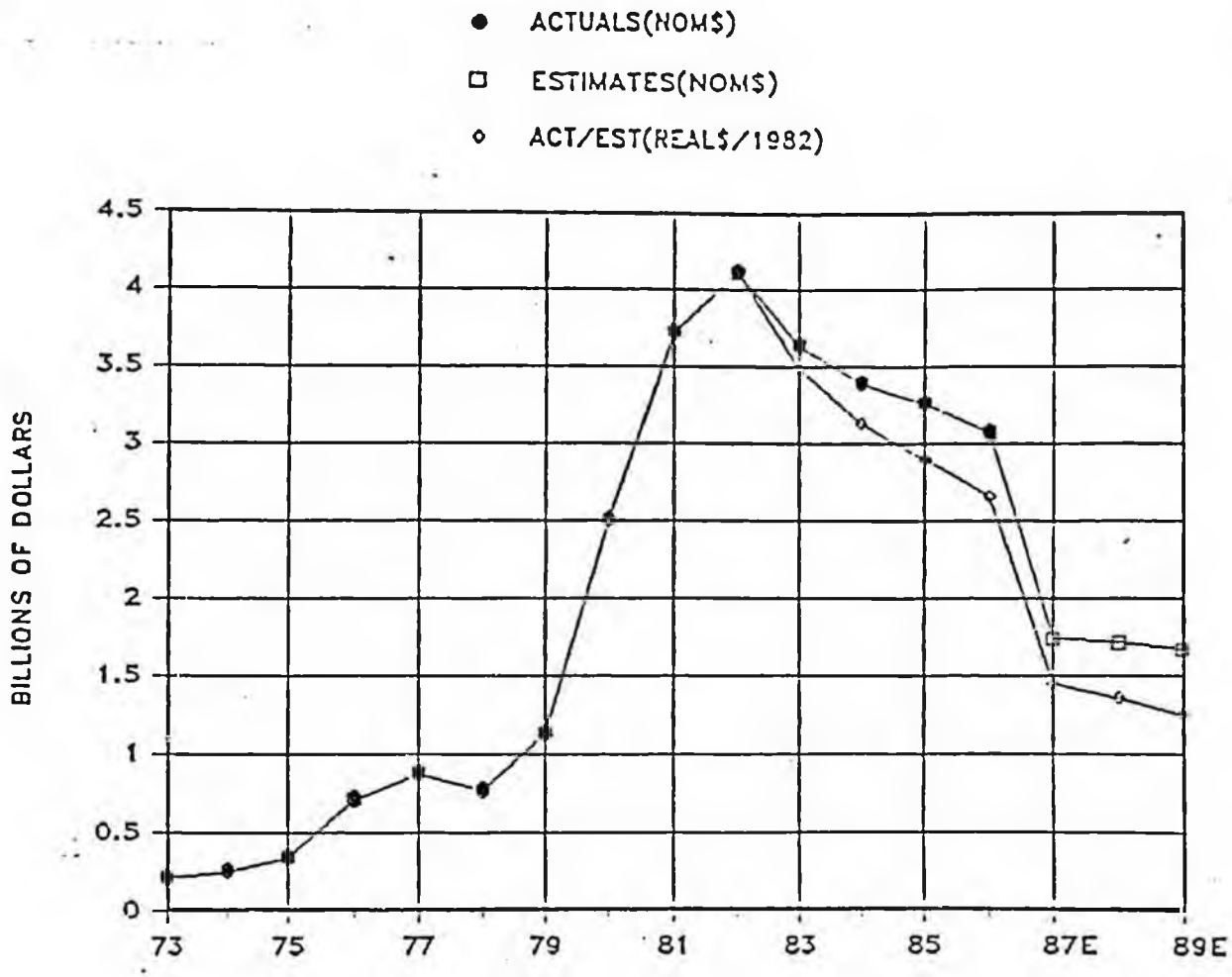
(11) The FY 87 figure reflects the estimated General Fund portion from refunds and expenses for prior years relative to the TAPS case ($65.7 million) and court costs relative to the ARCO settlement ($1.5 million). Consequently, $67.2 million is projected to be received during FY 87, but this figure is subject to future audits.

(12) The State, per AS 38.05.180, will be granting incentive credits against royalties, severance taxes, and rentals to the oil companies for drilling exploratory wells. The deduction is approximately $2.9 million which has not been subtracted from the aforementioned FY 87 figure of $1,741.3 million. Additional credits are anticipated in subsequent years.

FIGURE 2

GENERAL FUND UNRESTRICTED REVENUES

(NOMINAL DOLLARS VS. REAL DOLLARS)



Revenue Actuals (Nominal $)	
FY 73	.2082 billion
FY 74	.2549 billion
FY 75	.3334 billion
FY 76	.7098 billion
FY 77	.8743 billion
FY 78	.7649 billion
FY 79	1.1330 billion
FY 80	2.5012 billion
FY 81	3.7182 billion
FY 82	4.1084 billion
FY 83	3.6310 billion
FY 84	3.3901 billion
FY 85	3.2600 billion
FY 86	3.0755 billion

Revenue Estimates (Nominal $)	
FY 87	1.7413 billion
FY 88	1.7161 billion
FY 89	1.6721 billion

Revenue Actuals/Estimates (Real $/1982)	
FY 82	4.1084 billion
FY 83	3.4826 billion
FY 84	3.1347 billion
FY 85	2.9002 billion
FY 86	2.6584 billion
FY 87	1.4532 billion
FY 88	1.3587 billion
FY 89	1.2559 billion

TABLE II

Key Assumptions for June 1987
Petroleum Revenue Projections
For FY 1987 - FY 1989

Fiscal Year	($/bbl) Mean Wellhead Value	($/bbl) 30% Wellhead Value	Mean TAPS Throughput (MMbbs/day)	Mean Rate Inflation %
1987	$7.22	$7.05	1.84	3.59
1988	$9.90	$8.81	1.87	5.41
1989	$10.44	$8.84	1.89	5.42

Sales Price for
Alaska North Slope Crude Oil at Los Angeles, California

	Weighted Average	30% Case	
FY 87	$13.16	$12.99	per barrel
FY 88	$14.70	$13.61	per barrel
FY 89	$14.83	$13.23	per barrel

Sales Price for
Alaska North Slope Crude Oil at Houston, Texas

	Weighted Average	30% Case	
FY 87	$14.38	$14.21	per barrel
FY 88	$15.89	$14.80	per barrel
FY 89	$16.04	$14.44	per barrel

Weighted Average TAPS Tariff

FY 87	$4.25	per barrel
FY 88	$3.59	per barrel
FY 89	$2.84	per barrel

MEMORANDUM State of Alaska

TO: The Honorable Steve Cowper
Governor

DATE: March 20, 1987

FILE NO.:

THRU: Hugh Malone
Commissioner of Revenue

TELEPHONE NO.: 465-2173

SUBJECT: March Revenue Forecast

FROM: Vincent D. Wright
Chief of Research
Department of Revenue

The March 1987 unrestricted revenue forecast is complete and the numbers for FY 87, FY 88, and FY 89 are $1,598.4 million, $1,532.6 million, and $1,589.7 million respectively.

The changes when compared to the January 1987 forecast represent increases of $264.2 million, $207.6 million, and $215.8 million for FY 87, FY 88, and FY 89 respectively.

The FY 87 number must be adjusted upward by $65 million for TAPS legal expenses and refunds. When this adjustment is made, the bottom line for FY 87 then amounts to $1,663.4 million.

The FY 87 number represents the mean case, which is traditionally adopted this time of the year, whereas the figures for FY 88 and FY 89 represent the more conservative 30% case.

The situation relative to the oil outlook is extremely volatile and will likely remain so throughout the spring and summer. The problem centers around whether or not the fundamentals of supply and demand support current crude prices. The evidence to date suggests that they do not. The political side of the equation, mainly what oil producing OPEC and non-OPEC countries can do in controlling markets, is the primary factor propping up oil prices and this effort is tenuous at this particular point in time. The fact of the matter is that OPEC is undergoing, at this moment, a testing period insofar as its ability to hold together the production and pricing agreement reached December 21, 1986.

The most formidable and immediate problem working to undermine the OPEC agreement is the unwillingness of buyers to purchase the desired level of 15.8 million barrels per day at $18/barrel that OPEC would like to sell, although this in itself should help to reduce the excess supply of crude on world markets. The OPEC group is also confronted by the anticipated normal spring seasonal downturn in demand for certain types of fuel, the excess oil productive capacity of OPEC and non-OPEC countries alike, the relative decline in the value of the dollar which OPEC oil is pegged to, and adverse cash flow problems. The demand for petroleum products worldwide is sluggish at best with little chance for improvement in the immediate future. Compounding the problem is the price competitiveness of substitute energy resources. All the

aforementioned factors, which primarily revolve around the fundamentals of supply and demand, militate against OPEC being able to prevent, via political means, a collapse in oil prices.

On the other hand, if OPEC can restrain individual members from engaging in widespread violations of the current agreement, if non-OPEC countries continue to offer both tacit and overt support, if worldwide demand for petroleum products does not reverse itself, and if inventories are reduced throughout the spring and summer, then prices should steady and perhaps increase next winter. The odds against OPEC being able to hold their agreement together are enormous but we believe their chances of succeeding are better now than they were a few months ago. The one crucial element favoring success centers around OPEC's absolute necessity to succeed or confront as a consequence internal economic and financial failure. The prospect of this type of failure is perhaps the strongest motive holding OPEC together at this time. I want to reemphasize, however, that the situation is still tenuous and will likely remain so throughout the summer. This means that prudence dictates a cautious approach relative to our budgetary difficulties.

I should mention at this juncture that the numbers in this forecast are not based on any new revenue raising measures that might be passed during this session. If such measures are past, then the numbers will have to be adjusted accordingly.

I would like to further add the caveat that if there is a margin for error in this particular forecast it is obviously on the optimistic side i.e. the downside risks are much greater than any perceived upside potential.

I have attached for your perusal the details of this forecast along with the basic underlying assumptions, a short history of the states revenue picture, and charts indicating the nominal versus real dollar outlook.

VDW:mll
Attachments

TABLE I
General Fund Unrestricted Revenues
(Thousands of Current Dollars)

Taxes	FY 1986 Actual March	FY 1987 Estimate March	FY 1988 Estimate March	FY 1989 Estimate March
Income				
Corporate-General	11,200	14,000	15,000	15,500
Corporate-Petroleum	133,900	95,000	110,000	110,000
Gross Receipts				
Alaska Business License	2,100	2,000	2,000	2,000
Fish-Canned Salmon (1)	3,500	2,500	2,300	2,300
Fish-Shorebased (1)	10,100	11,500	10,000	10,000
Fish-Floating	7,500	8,000	7,600	7,600
Seafood Marketing	1,100	1,300	1,200	1,200
Salmon Enhancement	4,300	4,000	4,000	4,000
Insurance Companies(2)	21,100	18,500	18,200	17,900
Electric & Telephone Co-ops	1,900	1,900	1,900	1,900
Mining License Tax	300	300	400	400
Severance				
Oil & Gas Productior (3)	1,107,900	598,200	549,100	597,100
Oil & Gas Conservation	500	800	700	700
Property				
Oil & Gas	113,500	82,700	76,800	70,700
Sale/Use				
Alcoholic Beverages	13,300	12,800	12,300	12,000
Fuel Taxes-Aviation (4)	8,100	7,900	7,800	7,700
Fuel Taxes-Highway (4)	22,700	19,500	19,000	18,700
Fuel Taxes-Marine (4)	5,300	4,700	4,500	4,400
Tobacco Products (5)	4,900	6,900	6,600	6,400
Other				
Estate	700	1,100	700	700
Total Taxes	1,473,900	893,600	850,100	891,200
Licenses & Permits				
Business	11,300	10,500	10,800	11,000
Non-Business (6)	18,000	21,000	21,000	21,000
Total Licenses & Permits	29,300	31,500	31,800	32,000
Intergovernmental Receipts				
Federal Shared Revenues (7)	14,500	8,800	8,500	8,500
State Resource Revenue				
Sale/Use				
Bonus Sales (7) (8) (9) (10)	34,700	2,500	-0-	-0-
Investment Earnings (11)	195,200	160,000	90,000	45,000
Rents (7) (8) (9) (10)	6,200	5,500	6,000	6,500
Royalties (3) (7)	856,100	419,800	476,300	536,300
Sale of State Property	8,700	8,000	9,000	9,000
Gravel, Timber, etc. (12)	2,900	8,000	2,500	2,500
Facilities Related Charges				
Airports	1,500	1,600	1,600	1,600
Ferry System-Southeast	28,500	29,000	28,000	28,000
Ferry System-Southwest	3,800	3,800	3,700	3,700
Other	5,200	5,000	5,000	5,000

Service Related Charges				
Court System	5,100	5,300	5,400	5,600
Other	4,100	6,000	4,700	4,800
Total State Resources Revenues	1,152,000	654,500	632,200	648,000
Miscellaneous Revenues	13,000	10,000	10,000	10,000
Unrestricted Revenues	2,682,700	1,598,400	1,532,600	1,589,700
Plus: Special Settlements (13) (14)	392,800	65,000	-0-	-0-
Total Unrestricted Revenues (15)	3,075,500	1,663,400	1,532,600	1,589,700

(1) The FY 87, FY 88, and FY 89 figures reflect the recent enactment of a shorebased fisheries business tax credit per Ch. 79, SLA 1986. The Act took effect July 1, 1986.

(2) The FY 87, FY 88, and FY 89 figures reflect the enactment of Ch. 118, SLA 1986 which set the tax for domestic and foreign insurers, except hospital and medical service corporations, at 2.7 percent. Previously domestic and foreign insurers were taxed at 1.5 percent and 3.0 percent.

(3) The January forecast for FY 87 assumed the 30 percent case; however, the FY 87 March estimates have been changed to reflect the mean or average case. The forecasted numbers for FY 88 and FY 89 continue to assume the 30 percent case; however, if the mean case had been utilized for FY 88 and FY 89, the production taxes would change to $663.3 million and $734.0 million, respectively. The royalty figures would change to $575.9 million and $666.3 million, respectively. All of the forecasted numbers include the estimated TAPS settlement.

(4) Revenues from the three main categories of fuel tax are shown separately. However, under the provisions of AS 43.40.010(b), all refunds are made from the highway fuel tax account. If gross collections of highway fuel taxes remain constant, an increase in refunds for aviation and marine fuels could lower the net revenues shown for highway fuels. Also, increasing use is being made of tax credits, which can be taken in lieu of claiming a refund on certain non-taxable use of fuel (15 AAC 40.200). The FY 86 figure includes revenue for marine fuel tax collections on fuel purchased out-of-state but which is used in Alaska waters. A number of returns for taxes levied on in-state usage are currently in the appeal process and FY 87, FY 88, and FY 89 revenues will not be revised upward until that process is completed.

(5) Ch. 24, SLA 1985 raised the General Fund portion of the cigarette tax from a rate of 1-1/2 mills ($.0015) to 5-1/2 mills ($.0055) per cigarette. The Act took effect October 1, 1985.

(6) The FY 87, FY 88 and FY 89 figures reflect the enactment of Ch. 60, SLA 1986 which increased driver licensing fees and vehicle registration fees. The Act became effective September 1, 1986.

(7) Net Permanent Fund contribution by Ch. 18 SLA 1980.

(8) Reflects state lease sales of $16.3 million held September 24, 1985 (Sale 45A-North Slope Onshore and Sale 47 - Kuparuk Uplands), $3.0 million held February 25, 1986 (Sale 48 - Kuparuk Uplands and Sale 48A - Nikkelsen), $0.9 million held June 24, 1986 (Sale 49 - Cook Inlet), and $0.3 million held January 27, 1987 (Sale 51 - Prudhoe Bay Uplands). Due to the timing of collections, receipts from the June 1986 lease sale are shown as FY 87 revenue. The FY 87, FY 88, and FY 89 bonus figures represent the General Fund's 49.5 percent share.

(9) The FY 86 figure reflects the OCS "8(g)" revenue-sharing settlement of $51.4 million. The General Fund share represents 49.5 percent of the aforementioned total, whereas the Permanent Fund will receive 50.0 percent. The remaining 0.5 percent will be distributed to the Public School Fund. An additional $4.0 million is reflected in FY 87.

(10) The Department of Natural Resources projects the following FY 87, FY 88, and FY 89 state lease sales: FY 87 (Sale 50 - Camden Bay); FY 88 (Sale 54 - Kuparuk Upland, Sale 55 - Demarcation Point); and FY 89 (Sale 52 - Beaufort Sea, Sale 56 - Alaska Peninsula). However, bonus bids are impossible to anticipate prior to sales; therefore, no estimates are provided.

(11) The investment earning projections presented reflect the current composition of General Fund assets and current interest rates. The projections also reflect a drawdown in the level of General Fund assets over the projection period. The projected drawdown in assets is a result of projected revenue cash inflows consistent with the current revenue forecast and projected expenditure cash outflows consistent with the revised FY 87 budget and the Governor's, January 1987, recommended FY 88 budget. None of the Governor's proposed revenue enhancement or alternative funding measures have been reflected in the projections. Should proposed tax measures be enacted or should a portion of the Permanent Fund earnings be appropriated to the General Fund then these General Fund investment earning projections would be greater for FY 88 and FY 89.

(12) The FY 87 estimate reflects increased construction of roads and drilling pads as projected by the Department of Natural Resources.

(13) The FY 86 figure includes the $243 million the State received from the ARCO settlement on January 15, 1986.

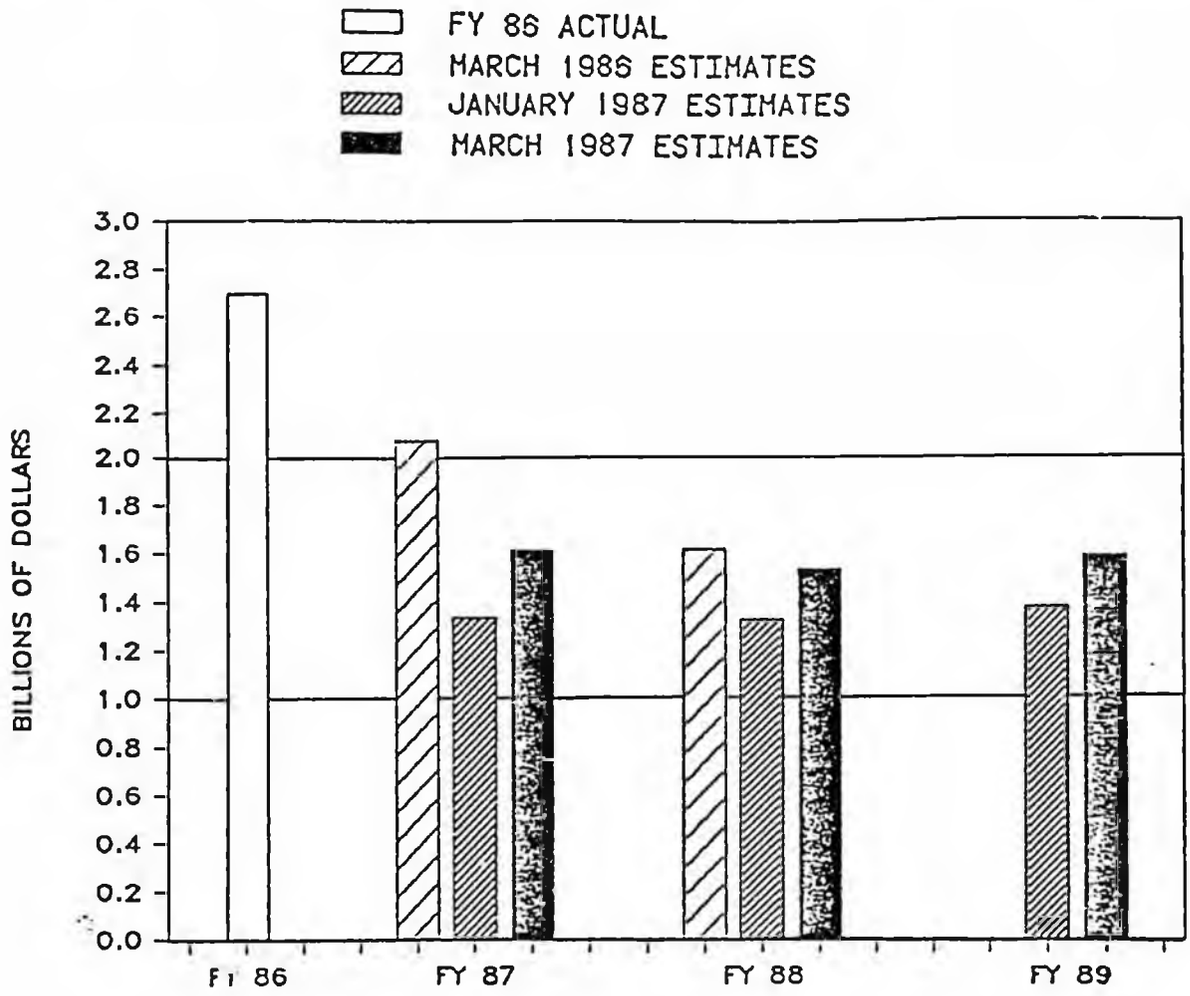
(14) The FY 86 and FY 87 figures reflect the estimated General Fund portion from refunds and expenses for prior years, relative to the TAPS case. The State received $149.8 million during FY 86 but this figure is subject to audit. Approximately $65.0 million is projected to be received during FY 87. This figure is also subject to future audits.

(15) The State, per AS 38.05.180, will be granting incentive credits against royalties, severance taxes, and rentals to the oil companies for drilling exploratory wells. The deduction is approximately $0.7 million which has not been subtracted from the aforementioned FY 86 figure of $3,075.5 million and approximately $2.9 million which has not been subtracted from the aforementioned FY 87 figure of $1,663.4 million. Additional credits are anticipated in subsequent years.

FIGURE 1

GENERAL FUND UNRESTRICTED REVENUES

(COMPARISON OF PRIOR FORECASTS)



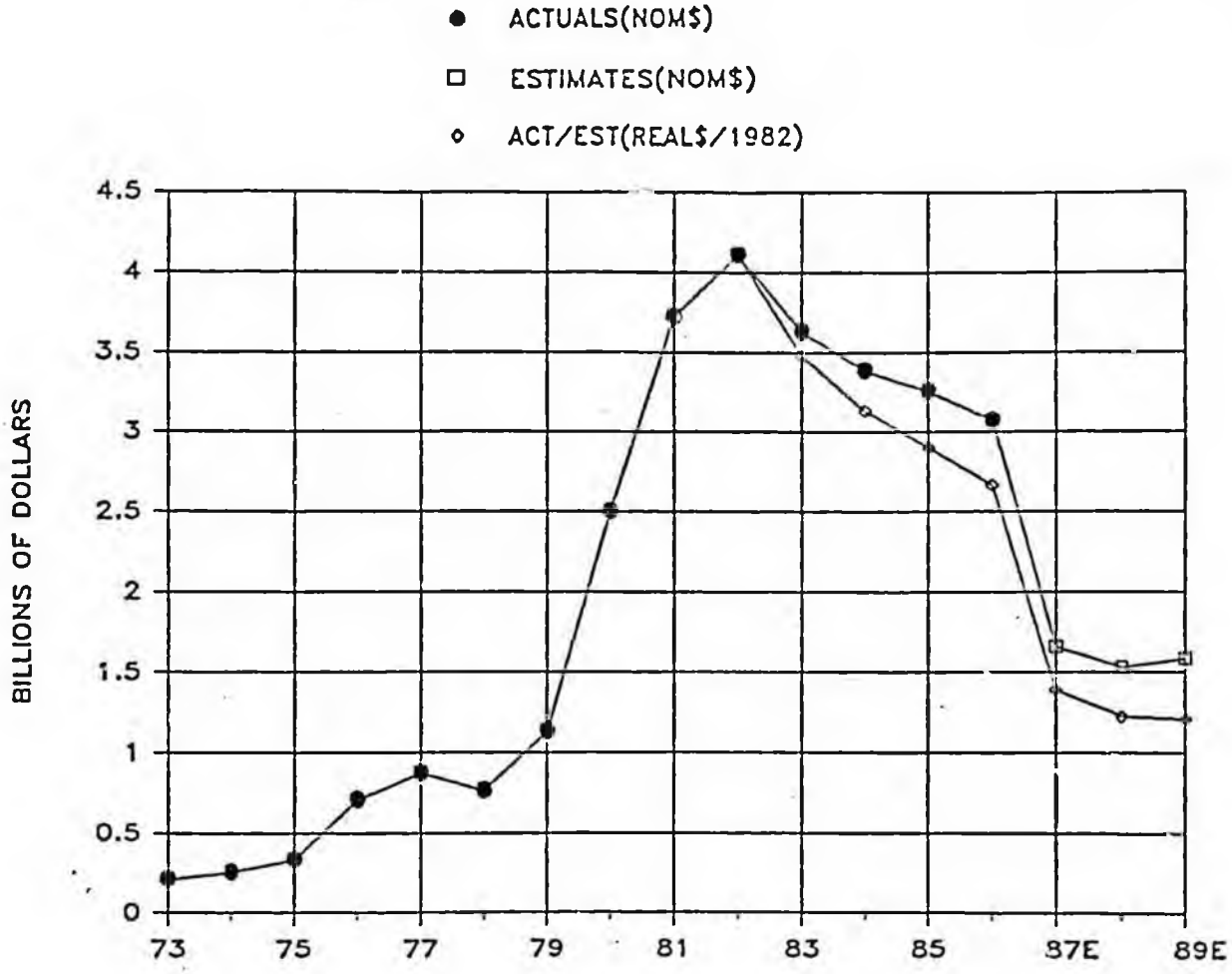
FY 86 Actual*	2.6827 billion
FY 87 Estimates*	
March 1986	2.0776 billion
January 1987	1.3342 billion
March 1987	1.5984 billion
FY 88 Estimates	
March 1986	1.6142 billion
January 1987	1.3250 billion
March 1987	1.5326 billion
FY 89 Estimates	
January 1987	1.3739 billion
March 1987	1.5897 billion

* IT SHOULD BE NOTED THAT ALL "SPECIAL SETTLEMENTS" HAVE BEEN EXCLUDED ABOVE IN FY 86 AND FY 87 IN ORDER TO BE CONSISTENT IN COMPARING PRIOR FORECASTS. THE FY 86 BOTTOM LINE WOULD INCLUDE AN ADDITIONAL $243.0 MILLION (ARCO SETTLEMENT) AND $149.8 MILLION (TAPS REFUNDS/LEGAL EXPENSES). FOR FY 87, THE ABOVE FIGURES WOULD INCLUDE AN ADDITIONAL $65.0 MILLION (TAPS REFUNDS/LEGAL EXPENSES).

FIGURE 2

GENERAL FUND UNRESTRICTED REVENUES

(NOMINAL DOLLARS VS. REAL DOLLARS)



Revenue Actuals (Nominal $)	
FY 73	.2082 billion
FY 74	.2549 billion
FY 75	.3334 billion
FY 76	.7098 billion
FY 77	.8743 billion
FY 78	.7649 billion
FY 79	1.1330 billion
FY 80	2.5012 billion
FY 81	3.7182 billion
FY 82	4.1084 billion
FY 83	3.6310 billion
FY 84	3.3901 billion
FY 85	3.2600 billion
FY 86	3.0755 billion

Revenue Estimates (Nominal $)	
FY 87	1.6634 billion
FY 88	1.5326 billion
FY 89	1.5897 billion

Revenue Actuals/Estimates (Real $/1982)	
FY 82	4.1084 billion
FY 83	3.4826 billion
FY 84	3.1347 billion
FY 85	2.9002 billion
FY 86	2.6641 billion
FY 87	1.3926 billion
FY 88	1.2258 billion
FY 89	1.2126 billion

TABLE II

Key Assumptions for March 1987
Petroleum Revenue Projections
For FY 1987 - FY 1989

Fiscal Year	($/bbl) Mean Wellhead Value	($/bbl) 30% Wellhead Value	Mean TAPS Throughput (MMbbs/day)	Mean Rate Inflation %
1987	$6.93	$6.61	1.83	3.47
1988	$9.11	$7.56	1.87	4.68
1989	$10.40	$8.40	1.89	4.85

Sales Price for
Alaska North Slope Crude Oil at Los Angeles, California

	Weighted Average	30% Case	
FY 87	$12.83	$12.51	per barrel
FY 88	$14.09	$12.54	per barrel
FY 89	$14.87	$12.87	per barrel

Sales Price for
Alaska North Slope Crude Oil at Houston, Texas

	Weighted Average	30% Case	
FY 87	$14.06	$13.74	per barrel
FY 88	$15.16	$13.61	per barrel
FY 89	$16.00	$14.00	per barrel

Weighted Average TAPS Tariff

FY 87	$4.25	per barrel
FY 88	$3.19	per barrel
FY 89	$2.75	per barrel

MEMORANDUM State of Alaska

TO: The Honorable Steve Cowper
Governor of Alaska

DATE: December 3, 1986

FILE NO.:

THRU:

TELEPHONE NO.: 465-2173

SUBJECT: January Revenue Forecast

FROM: Vincent D. Wright
Chief of Research
Department of Revenue

The January 1987 unrestricted revenue forecast is complete and the numbers for FY 87, FY 88 and FY 89 are $1,334.2 million, $1,325.0 million, and $1,373.9 million respectively. The numbers mentioned above are based on the 30% or more conservative case when compared to the mean case.

The changes when compared to the September forecast represent a decrease of $74.4 million for FY 87, but increases of $51.4 million and $111.4 million for FY 88 and FY 89.

For FY 87, when the expected $65 million in TAPS legal expenses and refunds is added, the bottom line then becomes $1,399.2 million.

The books have now been closed for FY 86 and the total unrestricted revenues for that year, not including special settlements, amount to $2,682.7 million. This number for FY 86 must be adjusted for two items. The first deals with the fact that we have received in the General Fund $149.8 million in legal expenses and refunds from the TAPS case. The second is the receipt on January 15, 1986 of $243 million for the ARCO settlement. When the $149.8 million and $243 million are added to FY 86, the bottom line then becomes $3,075.5 million.

The current situation relative to the oil picture is such that the underlying economic fundamentals of supply and demand do not support current price levels. The political element, OPEC control or lack of control, is primarily responsible for today's "relatively high priced oil". Since the political element supercedes the economic factor we must continue to expect a great deal of volatility in oil markets. This type of activity can whipsaw an economy such as ours.

The period we have to be most concerned about now is the spring of 1987. If large inventories persist, if normal seasonal factors prevail, and if it is perceived by oil traders that OPEC is having difficulty holding together its current agreement (due to expire at the end of December but expected to be renewed), then oil prices could plunge dramatically. We anticipate, in any case, a "normal drop" in oil prices this spring due to historical seasonal patterns but whether a total collapse occurs depends on OPEC's ability to hold together their current

agreement. In view of the internal dissension plaguing the OPEC membership, the outlook is not encouraging. I would like to further add the caveat that if there is a margin for error in this particular forecast we believe it is on the optimistic side i.e. the downside risks are much greater than any perceived upside potential.

I have attached eight letters written over the last two years to your predecessor on the subject of the State's oil outlook. These letters lay out in detail the unfolding of events in the world oil arena. You may find them interesting reading.

I have also attached for your perusal the details of this forecast along with the basic underlying assumptions, a short history of the State's revenue picture, and charts indicating the nominal versus real dollar outlook.

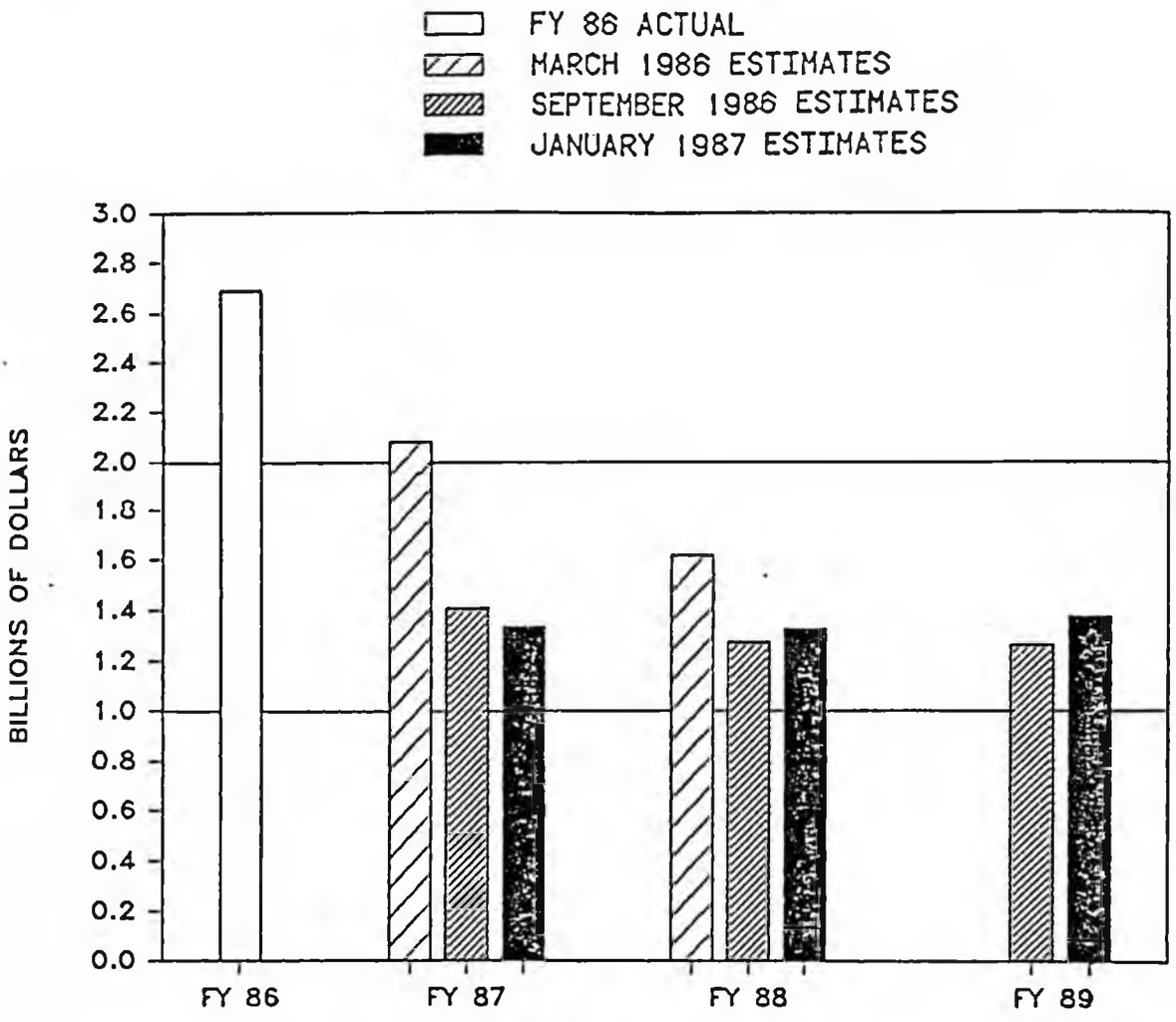
VDW:mkw

Attachments

FIGURE 1

GENERAL FUND UNRESTRICTED REVENUES

(COMPARISON OF PRIOR FORECASTS)



* IT SHOULD BE NOTED THAT THE ABOVE AMOUNTS DO NOT INCLUDE ANY SPECIAL SETTLEMENTS. THE FY 86 BOTTOM LINE WOULD INCLUDE AN ADDITIONAL $243.0 MILLION (ARCO SETTLEMENT) AND $149.8 MILLION (TAPS REFUNDS/LEGAL EXPENSES). FOR FY 87, THE ABOVE FIGURES WOULD INCLUDE AN ADDITIONAL $65.0 MILLION (TAPS REFUNDS/LEGAL EXPENSES).

TABLE I
General Fund Unrestricted Revenues
(Thousands of Current Dollars)

Taxes	FY 1986 Actual January	FY 1987 Estimate January	FY 1988 Estimate January	FY 1989 Estimate January
Income				
Corporate-General	11,200	14,000	15,000	15,500
Corporate-Petroleum	133,900	111,000	110,000	110,000
Gross Receipts				
Alaska Business License	2,100	2,000	2,000	2,000
Fish-Canned Salmon (1)	3,500	2,500	2,300	2,300
Fish-Shorebased (1)	10,100	11,500	10,000	10,000
Fish-Floating	7,500	8,000	7,600	7,600
Seafood Marketing	1,100	1,200	1,200	1,200
Salmon Enhancement	4,300	4,000	4,000	4,000
Insurance Companies(2)	21,100	20,000	19,600	19,200
Electric & Telephone Co-ops	1,900	1,900	1,900	1,900
Mining License Tax	300	300	400	400
Severance				
Oil & Gas Production (3)	1,107,900	459,200	453,900	493,600
Oil & Gas Conservation	500	700	600	600
Property				
Oil & Gas	113,500	82,700	76,800	70,700
Sale/Use				
Alcoholic Beverages	13,300	12,600	12,300	12,000
Fuel Taxes-Aviation (4)	8,100	8,000	8,000	8,000
Fuel Taxes-Highway (4)	22,700	20,500	20,000	20,000
Fuel Taxes-Marine (4)	5,300	4,100	4,100	4,100
Tobacco Products (5)	4,900	7,000	6,600	6,400
Other				
Estate	700	800	700	700
Total Taxes	1,473,900	772,200	757,000	790,200
Licenses & Permits				
Business	11,300	10,800	10,800	11,000
Non-Business (6)	18,000	21,000	21,000	21,000
Total Licenses & Permits	29,300	31,800	31,800	32,000
Intergovernmental Receipts				
Federal Shared Revenues (7)	14,500	8,500	8,500	8,500
State Resource Revenue				
Sale/Use				
Bonus Sales (7) (8) (9) (10)	34,700	2,400	-0-	-0-
Investment Earnings (11)	195,200	160,000	60,000	10,000
Rents (7) (8) (9) (10)	6,200	6,500	6,500	6,500
Royalties (3) (7)	856,100	277,100	390,200	455,400
Sale of State Property	8,700	8,500	9,000	9,000
Gravel, Timber, etc. (12)	2,900	8,000	2,500	2,500
Facilities Related Charges				
Airports	1,500	1,600	1,600	1,600
Ferry System-Southeast	28,500	29,000	29,000	29,000
Ferry System-Southwest	3,800	3,800	3,800	3,800
Other	5,200	5,000	5,000	5,000

Service Related Charges				
Court System	5,100	5,300	5,400	5,600
Other	4,100	4,500	4,700	4,800
Total State Resources Revenues	1,152,000	511,700	517,700	533,200
Miscellaneous Revenues	13,000	10,000	10,000	10,000
Total Unrestricted Revenues (13)(14)(15)	2,682,700	1,334,200	1,325,000	1,373,900

(1) The FY 87, FY 88, and FY 89 figures reflect the recent enactment of a shorebased fisheries business tax credit per Ch. 79, SLA 1986. The Act took effect July 1, 1986.

(2) The FY 87, FY 88, and FY 89 figures reflect the enactment of Ch. 118, SLA 1986 which set the tax for domestic and foreign insurers, except hospital and medical service corporations, at 2.7 percent. Previously domestic insurers were taxed at a 1.5 percent rate and foreign insurers at 3.0 percent.

(3) The forecasted numbers for FY 87, FY 88, and FY 89 assume the 30 percent case; however, if the mean case had been utilized for FY 87, FY 88, and FY 89, the production taxes would change to $504.6 million, $581.3 million and $649.5 million, respectively. The royalty figures would change to $325.0 million and $503.5 million, and $600.2 million, respectively. All of the forecasted numbers include the estimated tariff adjustment from the TAPS settlement.

(4) Revenues from the three main categories of fuel tax are shown separately. However, under the provisions of AS 43.40.010(h), all refunds are made from the highway fuel tax account. If gross collections of highway fuel taxes remain constant, an increase in refunds for aviation and marine fuels could lower the net revenues shown for highway fuels. Also, increasing use is being made of tax credits, which can be taken in lieu of claiming a refund on certain non-taxable use of fuel (15 AAC 40.200). The FY 86 figure includes revenue for marine fuel tax collections on fuel purchased out-of-state but which is used in Alaska waters. A number of returns for taxes levied on in-state usage are currently in the appeal process and FY 87, FY 88, and FY 89 revenues will not be revised upward until that process is completed.

(5) Ch. 24, SLA 1985 raised the General Fund portion of the cigarette tax from a rate of 1-1/2 mills ($.0015) to 5-1/2 mills ($.0055) per cigarette. The Act took effect October 1, 1985.

(6) The FY 87, FY 88 and FY 89 figures reflect the recent enactment of Ch. 60, SLA 1986 which increased driver licensing fees and vehicle registration fees. The Act became effective September 1, 1986.

(7) Net Permanent Fund contribution by Ch. 18 SLA 1980.

(8) Reflects state lease sales of $16.3 million held September 24, 1985 (Sale 45A-North Slope Onshore and Sale 47 - Kuparuk Uplands), $3.0 million held February 25, 1986 (Sale 48 - Kuparuk Uplands and Sale 46A - Mikkelsen), and $0.9 million held June 24, 1986 (Sale 49 - Cook Inlet). Due to the timing of collections, receipts from the June 1986 lease sale are shown as FY 87 revenue. The FY 87, FY 88, and FY 89 figures represent the General Fund's 49.5 percent share.

(9) The FY 86 figure reflects the OCS "8(g)" revenue-sharing settlement of $51.4 million. The General Fund share represents 49.5 percent of the aforementioned total, whereas the Permanent Fund will receive 50.0 percent. The remaining 0.5 percent will be distributed to the Public School Fund. An additional $4.0 million is reflected in FY 87.

(10) The Department of Natural Resources projects the following FY 87, FY 88, and FY 89 state lease sales: FY 87 (Sale 51 - Prudhoe Bay Uplands, Sale 50 - Camden Bay); FY 88 (Sale 54 - Kuparuk Upland, Sale 52A - Nechelik, Sale 55 - Demarcation Point); and FY 89 (Sale 52 - Beaufort Sea, Sale 56 - Alaska Peninsula). However, bonus bids are impossible to anticipate prior to sales; therefore, no estimates are provided.

(11) The FY 88 estimate for investment earnings assumes that the balances of certain funds and accounts which are commingled with the General Fund for investment may not be drawn down to meet General Fund cash expenditure needs in FY 87. Should the budget reserve fund or the railbelt energy fund be appropriated for other purposes or should the attorney general opine that certain of the commingled funds and accounts may be drawn down for General Fund expenditures in FY 87, the FY 86 estimate for investment earnings would be significantly reduced. Estimates for investment earnings for FY 88 and FY 89 do assume that moneys from these accounts and funds will be appropriated and spent in those years.

(12) Estimates reflect increased construction of roads and drilling pads as projected by the Department of Natural Resources; however, some of these projects may be delayed or changed due to permit denials or environmental impact statement requests.

(13) The State, per AS 38.05.180, will be granting incentive credits against royalties, severance taxes, and rentals to the oil companies for drilling exploratory wells. The deduction is approximately $0.7 million which has not been subtracted from the aforementioned FY 86 figure of $2,682.7 million and approximately $2.9 million which has not been subtracted from the aforementined FY 87 figure of $1,334.2 million. Additional credits are anticipated in subsequent years.

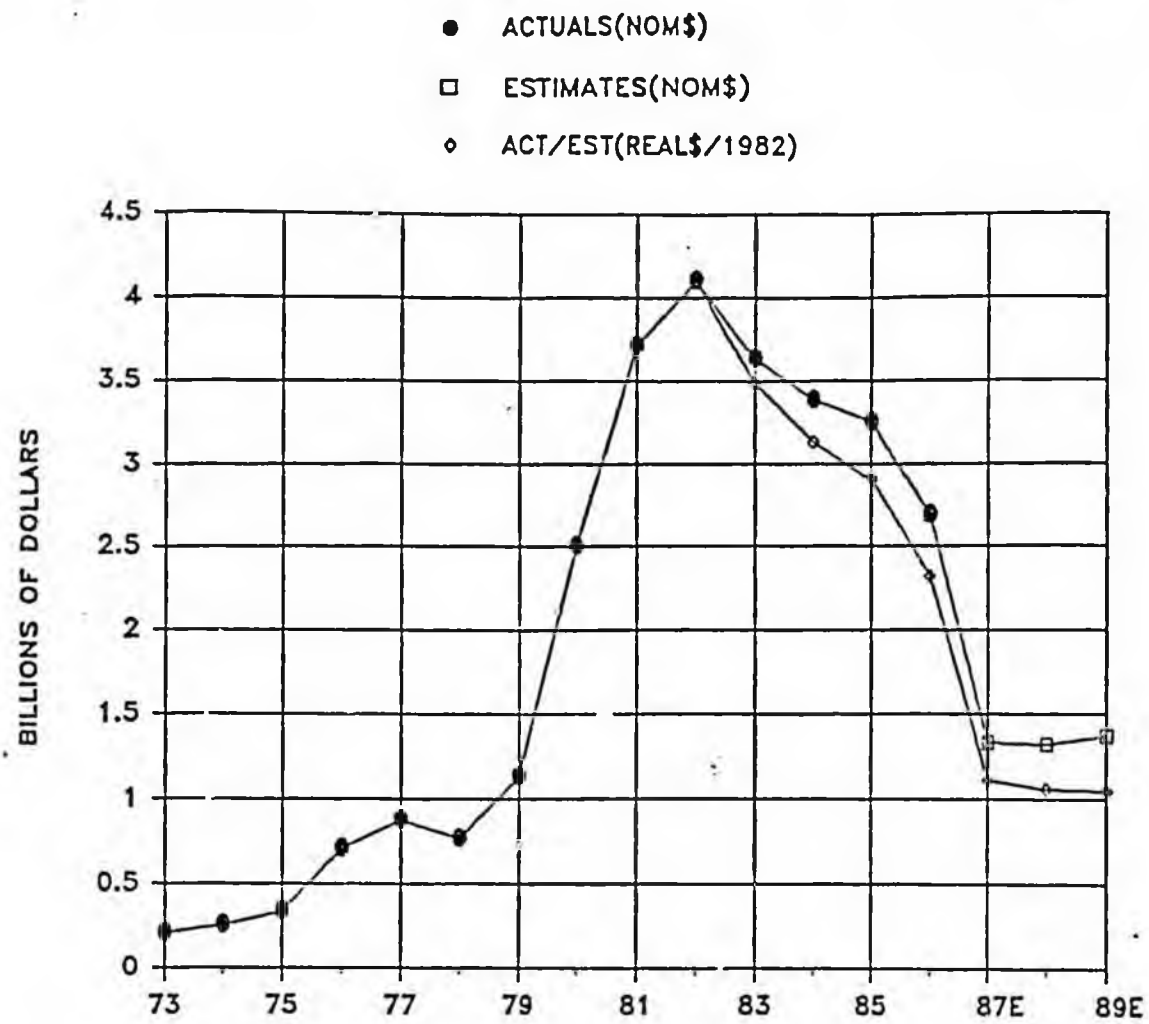
(14) The FY 86 figure does not include the $243 million the State received from the ARCO settlement on January 15, 1986.

(15) The FY 86 and FY 87 figures do not include the estimated General Fund portion from refunds and expenses for prior years, relative to the TAPS case. The State received $149.8 million during FY 86 but this figure is subject to audit. Approximately $65.0 million is projected to be received during FY 87. This figure is also subject to future audits.

FIGURE 2

GENERAL FUND UNRESTRICTED REVENUES

(NOMINAL DOLLARS VS. REAL DOLLARS)



Revenue Actuals (Nominal $)	
FY 73	208.2 million
FY 74	254.9 million
FY 75	333.4 million
FY 76	709.8 million
FY 77	874.3 million
FY 78	764.9 million
FY 79	1,133.0 million
FY 80	2,501.2 million
FY 81	3,718.2 million
FY 82	4,108.4 million
FY 83	3,631.0 million
FY 84	3,390.1 million
FY 85	3,260.0 million
FY 86	2,682.7 million

Revenue Estimates (Nominal $)	
FY 87	1,334.2 million
FY 88	1,325.0 million
FY 89	1,373.9 million

Revenue Actuals/Estimates (Real $/1982)	
FY 82	4,108.4 million
FY 83	3,482.6 million
FY 84	3,134.7 million
FY 85	2,900.2 million
FY 86	2,323.2 million
FY 87	1,112.4 million
FY 88	1,056.5 million
FY 89	1,047.5 million

* IT SHOULD BE NOTED THAT THE ABOVE AMOUNTS DO NOT INCLUDE ANY SPECIAL SETTLEMENTS. THE FY 86 BOTTOM LINE WOULD INCLUDE AN ADDITIONAL $243.0 MILLION (ARCO SETTLEMENT) AND $149.8 MILLION (TAPS REFUNDS/LEGAL EXPENSES). FOR FY 87, THE ABOVE FIGURES WOULD INCLUDE AN ADDITIONAL $65.0 MILLION (TAPS REFUNDS/LEGAL EXPENSES).

TABLE II

Key Assumptions for January 1987
Petroleum Revenue Projections
For FY 1987 - FY 1989

Fiscal Year	($/bbl) Mean Wellhead Value	($/bbl) 30% Wellhead Value	Mean TAPS Throughput (MMbbs/day)	Mean Rate Inflation %
1987	$5.51	$4.74	1.81	3.89
1988	$8.61	$6.68	1.73	4.58
1989	$10.59	$8.03	1.66	4.58

Sales Price for
Alaska North Slope Crude Oil at Los Angeles, California

	Weighted Average	30% Case	
FY 87	$11.18	$10.41	per barrel
FY 88	$13.57	$11.64	per barrel
FY 89	$14.89	$12.33	per barrel

Sales Price for
Alaska North Slope Crude Oil at Houston, Texas

	Weighted Average	30% Case	
FY 87	$12.59	$11.82	per barrel
FY 88	$14.97	$13.04	per barrel
FY 89	$16.39	$13.83	per barrel

Weighted Average TAPS Tariff

FY 87	$4.25	per barrel
FY 88	$3.76	per barrel
FY 89	$3.44	per barrel

Alaska State Legislature

REPRESENTATIVE
MARK BOYER

HOUSE FINANCE COMMITTEE

House of Representatives

FAIRBANKS

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FAIRBANKS, ALASKA 99701
(907) 456-6473

JUNEAU

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JUNEAU, ALASKA 99811
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ELF REPEAL, NOT PERMANENT OR RAILBELT FUNDS, SHOULD FUND RECOVERY

I recently answered a "question of the week" in the other local newspaper, which asked if I supported the Governor's proposed education endowment, by stating that I didn't think we should tap the Permanent Fund earnings for a basic need such as education after we had just given the oil industry a $150 million tax break through our failure to act on the Economic Limit Factor. A letter to the editor of that newspaper the next week questioned the soundness of my judgement in making such a statement days after ARCO announced that it was planning to spend $300 million on North Slope construction. The writer of that letter made an assumption which is not supported by fact or recent experience: that Fairbanks will benefit in any meaningful way from that proposed activity on the Slope this season. 1986 saw the largest sealift in North Slope history, but if you looked around Fairbanks and talked to local businessmen and construction workers, as I did during five months of campaigning that year, you never would have guessed it.

We in Fairbanks have come to have much in common with the residents of Southeast Alaska, who maintain that the only benefits which they derive from oil development are those which are

provided by the state government and funded by oil taxes. Since the expiration of the Project Labor Agreements, which mandated dispatch of workers from Fairbanks hiring halls, in December of 1985, the number of Fairbanksans going to work on the Slope has dropped precipitously, even during periods of major construction activity. Those Alaskan residents who are fortunate enough to secure employment on the Slope, which continues to be a haven for out-of-state workers, are hired out of Anchorage and Kenai.

Fairbanks businesses have, with few exceptions, fared no better than our local construction workers in obtaining North Slope work. While the prospect of a few million dollars worth of mini-module construction is dangled before our local firms (and eventually awarded to in Mat-Su and Anchorage) hundreds of millions of dollars is spent on Outside module fabrication. I guess they figure that the same workers who are installing the "maxi" modules up North might as well build them, back home in Louisiana.

I might feel differently about an undeserved and inappropriate tax break for the Prudhoe Bay operators if I saw some indication that their activities are going to directly benefit workers and businesses in Fairbanks. That is clearly not the case, however, and I am more concerned with providing important government services to Fairbanks and the rest of Alaska without raiding the Permanent Fund or the Railbelt Energy Fund than I am with protecting the oil companies' bottom line. New

figures just released by the Department of Revenue show that repeal or suspension of the Economic Limit Factor for the Prudhoe Bay oilfields would have added $187.4 million to state revenues in FY 88 and $227.6 million in the fiscal year for which we are currently budgeting, FY 89. Given the choice of using Permanent Fund earnings or Railbelt funds to fund worthwhile programs which will push our FY 89 budget beyond expected revenues or repealing the ELF, the choice is clear.

Here are just a few of the budget items which fall into the "great idea, but how are you going to fund it?" category, and which we might fund with an additional $227 million in the FY 89 budget:

$20 million to implement the Governor's recommendations from his Interim Children's Commission for intervention and prevention services for children at risk of sexual and physical abuse, neglect, domestic violence, suicide, and substance abuse.

$30 million to increase Municipal Assistance and Revenue Sharing to FY 87 levels to help local governments adjust to their changed financial condition without undue burden on local taxpayers already struggling to make ends meet.

$75 million for an additional capital budget, to include

funds for continued progress on University construction projects underway statewide, including the Butrovich Building and the TVCC Downtown Center, and to begin construction of the Natural Sciences Facility at UAF.

$4 million for increased faculty compensation at the University of Alaska, to retain and recruit high quality faculty.

$40 million for other economic development or recovery projects, which might include: mortgage relief for AHFC homeowners; increases in the operating budget for programs which can facilitate private sector development, such as DNR, DEC, and Fish and Game; economic development grants through DCED.

$3 million for inspection of school buildings for asbestos and development of management plans as required by federal law.

$5 million to continue to meet our commitment to mental health as a result of last year's mental health lands settlement.

$3 million to hospitals to help offset their catastrophic illness problem, which this year exceeds $15 million statewide.

$1.5 million to bring services for the developmentally disabled back to FY 86 levels.

$46 million for deposit in the budget reserve.

Of course, this is only one possible scenario for using an additional $227 million in state revenues this year, but it gives an idea of the positive impact that such an infusion could have on our economy, without raiding the permanent or Railbelt funds.

The allegedly "marginal" Prudhoe Bay oilfields out-produce most others in the world at a fraction of the average worldwide per barrel production cost, yet the Senate let the ELF take effect last June, when it was estimated that the tax break (the repeal of which was decried as a tax increase by Senators) would cost the state $80 million in FY 88. Increases in the price of oil, in throughput of the TAPS line, and in drilling activity have all served to amplify the effect of the ELF beyond that initial estimate to the $187.4 million figure cited earlier.

A primary reason for the dramatic increases in lost revenues is the fact that the tax break allowed by the Economic Limit Factor is based on production per well. The Prudhoe Bay operators have embarked on a major drilling program, funded by the ELF, to increase the number of wells, so that peak production is maintained, but at a lower number of barrels per well. The incentive to drill more wells to come under the ELF is like paying

farmers not to plant their crops. This has served to maximize the ELF giveaway beyond the expectations of anyone studying the issue last year. The revenue loss from ELF for FY 89 was expected to be $100 million. A Department of Revenue report released earlier this week projects a loss of $227 million for that year, and further losses of $280 million, $272 million, $248 million, and $216 million for the four succeeding fiscal years (a total of $1.4 billion, FY 88 - FY 93). Commissioner of Revenue Hugh Malone has aptly described this policy as "self-inflicted poverty."

The most ironic aspect of this situation is the fact that the formula for calculating the Economic Limit Factor which is contained in HB 164 is more favorable to truly marginal oil fields than the current formula. There was an audible thud in the House Finance Committee hearing on HB 164 last session as oil company lobbyists' jaws dropped when they heard the representative of Conoco, whose company operated the one truly marginal field on the North Slope until the price drop forced its closure, testify in support of HB 164. The Conoco representative stated that under the new ELF formula the Milne Point fields mothballed by Conoco would come back on line much sooner than under the present formula. If there had been any doubt that the resistance to ELF repeal was motivated more by a desire to give Big Oil a hefty tax cut than a fear of providing a disincentive to development of marginal fields, this testimony alone should have dispelled it. HB 164 passed the House on a vote of 25 - 15 last April. It has languished in the Senate State Affairs Committee ever since.

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB 164(Fin) am
PUBLISH DATE: _____

FISCAL NOTE

REQUEST: _____

Revision Date: March 4, 1988
Title: An Act Relating to the Oil and Gas Properties Production Tax and Effective Date
Sponsor: Rules/Governor
Requestor: _____

Agency Affected: _____
BRU: _____
Components: _____

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						
CAPITAL						
→ REVENUE	187,410	227,630	280,260	272,570	248,510	216,540

Lost if ELF is not modified by passage of this bill

$1,432,920,000 in 6 yrs.

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached)

Prepared by: Charles L. Logsdon
Division: Oil and Gas Audit
Phone: 277-5627
Date: March 4, 1988

Approved by Commissioner: Hugh Malone for FIR
Agency: Revenue
Date: 3/8/88

Distribution: (by preparer)
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)

This bill would effectively increase the severance tax rate on fields producing greater than approximately 120,000 barrels per day. At the same time fields producing less than this amont would be taxed at a lower rate. The relative increase or decrease would depend on the relative per well productivity of the field. The estimates contained in this fiscal note are based on the Department of Revenue March 1988 average assumptions about production and wells and the September 1988 average expected oil price.

The following tables illustrate both the revenue and tax rate impact of the bill by North Slope oil field.

Revenue Impact by North Slope Oil Field
(Millions Dollars)

Fiscal Year	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	West Sak	Thomson	Seal	Niakuk	North Slope
	133.57	59.86								137.4/
1988	[illegible]	[illegible]	0	0	-6.02	0	0	0	0	[illegible]
1989	161.97	72.11	0	0	-6.45	0	0	0	0	227.63
1990	291.28	88.64	0	-2.48	-7.13	0	0	0	0	280.26
1991	235.52	50.55	0	-2.54	-6.8	0	0	0	-5.16	272.57
1992	237.23	51.09	-11.78	-2.85	-8.98	0	-6.45	0	-9.8	248.51
1993	230	50.58	-29.72	-6.9	-8.37	0	-8.33	0	-10.72	216.54
1994	220.71	49.15	-30.2	-9.14	-9.22	0	-9.15	0	-12.27	199.38
1995	215.83	41.79	-33.15	-10.49	-10.02	0	-10.02	0	-7.92	185.22
1996	204.76	30.67	-33.88	-10.82	-11.1	0	-11	0	-8.68	159.95
1997	201.93	19.69	-34.84	-10.67	-11.72	0	-14.73	0	-8.11	141.55
1998	219.57	9.89	-35.72	-1.19	-12.35	0	-16.03	-12.39	-8.22	134.51
1999	210.3	3.28	-32.94	-6.64	-12.49	0	-17.3	-10.86	-9.69	124.26
2000	230.27	1.62	-36.84	-3.64	-12.91	0	-18.56	-5.78	-10.45	143.71
2001	232.3	.53	-32.73	-1.01	-14.48	0	-17.3	-6.3	-8.77	152.69
2002	235.74	-.02	0	-.02	-15.66	0	-17.47	-6.72	-6.38	189.47
2003	339.18	-.09	0	-.03	-15.52	0	-14.75	-8.86	-25.03	274.9
2004	353.23	-.08	0	0	-15.54	0	-10.36	-9.31	-20.3	302.54
2005	347.35	-.03	0	0	-15.49	0	-6.53	-9.79	-18.94	296.47
Total Revenue										
Nominal	4210.52	534.93	-311.85	-68.42	-200.23	0	-173.09	-70.01	0	3917.1
10%	1755.01	350.66	-125.17	-31.41	-78.62	0	-60.13	-18.28	0	1796.06
8%	2041.51	378.38	-148.47	-35.32	-92.45	0	-73.46	-23.57	0	2045.62

Change in tax rate

Year	Prudhoe	Kuparuk	Milne	Endicott	Lisburne	West Sak	Thomson	Seal	Niakuk
1988	.02487	.071445	0	0	-.03159275	0	0	0	0
1989	.02487	.071445	0	-.00346675	-.03198475	0	0	0	0
1990	.02487	.071445	0	-.001568	-.0276635	0	0	0	-.07216475
1991	.02487	.071445	0	-.00150675	-.02718275	0	0	0	-.0873915
1992	.02487	.071445	0	-.00885675	-.0230055	0	0	0	-.08975575
1993	.02487	.071445	0	-.018285	-.02766	0	-.0320215	0	-.0878325
1994	.02487	.071445	0	-.018235	-.02766	0	-.03193575	0	-.091483
1995	.02487	.071445	0	-.018235	-.02766	0	-.0318255	0	-.08736
1996	.02487	.071445	0	-.018235	-.02766	0	-.0317275	0	-.089505
1997	.02487	.071445	0	-.018285	-.02766	0	-.03095575	0	-.089565
1998	.02487	.071445	0	-.018285	-.02765	0	-.03717	0	-.089205
1999	.02487	.071445	0	-.018285	-.02766	0	-.050835	-.002009	-.08976
2000	.02487	.071445	0	-.018235	-.02766	0	-.059235	-.0023275	-.090225
2001	.02487	.071445	0	-.018285	-.02766	0	-.06369	-.00231525	.00063
2002	.02487	.071445	0	-.018285	-.02766	0	-.067425	-.00231525	0
2003	.02487	.071445	0	-.018235	-.02765	0	-.060735	-.00197225	0
2004	.02487	.071445	0	-.018285	-.02766	0	-.049425	-.002085	0
2005	.02487	.071445	0	-.018235	-.02766	0	0	0	0

Alaska State Legislature

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Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

March 10, 1988

The Honorable Steve Cowper
Alaska State Capital
P. O. Box A
Juneau, Alaska 99811

Dear Governor Cowper,

Thank you for your letter of March 2, 1988 requesting an early hearing on CSHB 164, the so-called ELF bill. Your letter states that "new information has become available suggesting that the ELF factor is creating an incentive for operators to drill additional wells" which in turn is leading to larger than expected revenue "losses." Responding to your letter I would encourage you to consider the following:

1. ELF is working just as intended. That is, it is providing an incentive for producers to follow full and optimal development programs at Prudhoe Bay and to delay the onset of field decline. The decline at Prudhoe has been pushed back to mid-1989. In fact, absent the extensive drilling and workover program in progress today, the decline would have been far greater than any revenue that might be "lost" because these wells are being drilled.

2. In the next two years the state will likely receive an additional $524 million in royalty and severance tax revenue over the June 1987 forecast by the Department of Revenue. Although oil prices have risen since this forecast, I believe the ELF relief that some are now complaining about, can be fairly viewed as an investment that is generating a return of better than 70 percent directly to the state. It seems like a pretty good investment.

3. The cost of the industry's current drilling program on the North Slope is estimated at over $400 million. No

prudent businessman would spend $400 million simply to reduce severance tax by $30 million per year, which is the average impact for 1987 and 1988 fiscal years, according to Charles Logsdon's February 19th memorandum to Commissioner Malone.

4. The bulk of the current $400 million drilling program is being spent in Alaska. Each of the eight rigs at Prudhoe, Kuparuk, and Endicott directly employs over 100 Alaskans, with over 200 more indirect jobs in support industries. This total computes to over 2400 full-time jobs, and is even greater than the number of jobs that we hope will be created under the $75 million "jobs bill."

5. In the past 16 months, the oil industry has brought on line major investments in the Lisburne and Endicott fields and in the central gas facility at Prudhoe Bay, despite the gyrations in oil prices. The collective capital costs for these investments is over $3 billion. As a result, production of oil (and gas liquids) has risen by more than 210,000 barrels a day, and the additional reserves to be recovered have increased by more than one billion barrels. The confidence of the industry to continue to make these investments during a period of price instability will be due in major part to its perception of a stable tax environment in Alaska.

6. With regard to the development of small and marginal fields, I would remind you of AS 43.55.013(d). This statute is specifically designed to provide additional aid to marginal fields by rebutting the 300 barrel/day presumptions. Reasonable application of this section by the Department of Revenue should provide appropriate severance tax relief for the small and marginal fields you were referring to. As you know, Conico, for their Milne Point Field, unsuccessfully attempted to utilize this statute.

Alaska has become the number one oil-producing state as a result of continued investment by the oil companies in Alaska, as investments in the lower 48 shrank. Since 1981, our stable tax environment has been a key to encouraging investment in Alaska and will continue to encourage investment in the future. I am committed to keeping that stable tax environment in the face of opposition of those interested only in squeezing more money to spend on Government, out of the oil companies who should be treated as partners.

It is for these reasons that CSHB 164 dated 4-15-87 will remain in the Senate State Affairs Committee.

Sincerely,

Senator Mitch Abood,
Chairman

MA/kd

cc: Senate President Jan Faiks
Speaker of the House Ben Grussendorf
Commissioner Hugh Malone, Department of Revenue

ELF BULLETS

• As originally enacted in 1978, ELF was intended to give producers a break on severance taxes on low-production wells such as those in Cook Inlet. When Republicans took control of the House in the 1981 coup, they adopted the Senate Republicans' rewrite of the ELF law, which had the effect of allowing the tax break to be applied to Prudhoe Bay starting in 1987, well in advance of the "supergiant" field beginning its production decline.

• The House last year passed and sent to the Senate new legislation that would close the loophole allowing high-production fields to reap the tax-avoidance benefits of the ELF law. If the Senate does not approve the House bill, the State of Alaska will lose an estimated $415 million over this fiscal year and the next, according to the Department of Revenue. The five-year loss, through FY 92, is estimated to total $1.2 billion.

• The oil companies argue that changing the ELF now could cause them to cut some of the 2,400 jobs they claim the tax break has allowed them to bring to their North Slope operations, and they'd prefer the Legislature cut the state budget by $400 million to cover the ELF loss. We know that nowhere near 2,400 North Slope jobs have been created, but even if that number were true, it's hardly likely the Alaska economy would receive the full benefit of those jobs, given the industry's history of hiring out-of-state residents to work on the Slope. Even more significantly, if we were to follow the industry's advice and cut another $400 million from the state budget, the economy would lose more than 9,500 jobs -- jobs now held by Alaskans, not temporary workers who send their paychecks home to other states.

• The oil companies also argue that changing the ELF law to avoid the anticipated loss would disrupt their "stable tax climate." The implication that changing the ELF would represent an unfair tax burden on the industry or would somehow jeopardize profits simply is not supportable. The fact is the industry long ago recovered the initial capital costs from North Slope operations; after deducting all taxes, operating costs and even new investment costs, the companies as of 1986 h[illegible]ll managed to take approximately $18.6 billion in net profits o[illegible] Alaska.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

P.O. Box Y, State Capitol
Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

April 27, 1988

MEMORANDUM

TO: Representative Sam Cotten

FROM: Brad Pierce
Legislative Analyst

RE: **Oil Industry Facts**
Research Request 88.236

You requested this agency to provide some basic economic and financial facts about oil industry operations in Alaska and the profitability of the petroleum transportation network between the North Slope and the Gulf Coast of the United States. Specifically, you asked:

- Has the number of jobs on drilling rigs on the North Slope increased since the Economic Limit Factor (ELF) was applied to Prudhoe Bay and Kuparuk production?
- How much revenue and profit do oil companies make from the Trans-Alaska Pipeline System (TAPS)?
- How much revenue and profit do oil companies make from their tanker operations?
- How much revenue and profit do oil companies make from the Panama pipeline?
- Compare petroleum taxes and royalties charged by the State of Alaska with those charged by other oil producing states.
- Discuss the terms of the TAPS tariff settlement and their effect on the state's revenues.

We address your questions in separate sections of this memorandum. Much of the information we have gathered comes from previous House Research memorandums, a recent Office of Management and Budget report--"The ELF: A Policy Perspective," and various issues of Petroleum Intelligence Weekly.

Pre- and Post-ELF North Slope Oilfield Employment

The ELF is a tax reduction calculation that is applied to the state severance tax rate on the basis of average daily per-well productivity in a given oilfield. When enacted as part of a larger overhaul of the state's oil taxation package in 1981, the ELF was designed to encourage development of marginal fields. The Prudhoe Bay and Kuparuk fields, which are the largest and most profitable in North America, were specifically exempted from the ELF for the first ten years following commercial production. In June 1987, the moratorium on applying the ELF to the Prudhoe Bay and Kuparuk fields ended. The state revenue loss of applying the ELF to these fields in FY 88 is about $150 million. A new formula for calculating the ELF is incorporated into legislation (CSHB 164) which has passed the House. This revised formula would reduce the severance tax reduction provided to the Prudhoe Bay and Kuparuk fields and increase the reduction to smaller fields.

Proponents of applying the original ELF to Prudhoe Bay and Kuparuk claim that by providing an incentive to drill more production wells, it will increase oil field employment, and that the economic effects of this private sector investment will offset any revenue loss to the state. Opponents say the ELF has very little to do with incentives to drill additional production wells in highly profitable fields. They argue that the key variable in an oil company's decision to drill additional wells is the expected price of crude oil and whether the marginal productivity of an additional well can be expected to justify the investment. They note that the difference in severance tax per barrel between the original and revised ELF formula is $0.21 at Prudhoe Bay and $0.42 at Kuparuk on a commodity that has varied in price by as much as $20 per barrel during the past ten years of profitable North Slope operations.[1]

The Department of Labor (DOL) maintains statistics on the number of oilfield jobs on the North Slope, which are compiled quarterly. There is a two quarter lag in the availability of employment information, so the only comparable pre- and post-ELF North Slope oil and gas industry employment data currently available are for the third quarters of 1986 and 1987. Average monthly oil and gas employment on the North Slope during the third quarter 1986 was 2,416. During the third quarter 1987, average employment

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[1] "March 1988 Revenue Forecast," Alaska Department of Revenue, March 23, 1988.

was 3,095. Thus, average oil and gas industry employment grew by 679 or 22 percent. Note that this is a very limited database from which to draw conclusions. Note also that according to the Department of Natural Resources, Division of Oil and Gas, the weighted average wellhead price of oil in September 1986 was $5.06 per barrel for Kuparuk and $4.85 at Prudhoe Bay. In September 1987, the wellhead prices were $10.84 and $11.84 respectively.

The DOL has also gathered occupational profile data on oilfield employment, i.e., the number of drillers, service workers, etc., from surveys of employers since late 1986 (a detailed list of drilling company occupations and employment is provided in Attachment A). Thus, we can offer a limited comparison of pre- and post-ELF oilfield drilling company employment on the North Slope. The DOL estimates there were 548 drilling workers employed on the North Slope during the fourth quarter of 1986 compared with 501 in the fourth quarter of 1987 (the only two quarters for which data are available). Thus, according to DOL data, drilling employment has actually declined by about nine percent since the ELF went into effect for the Prudhoe Bay and Kuparuk fields. Again, this is a very small number of observations from which to draw conclusions.

There is little doubt that the 7 to 14 percent anticipated reduction in state revenues from imposition of the original ELF on Prudhoe Bay and Kuparuk will have far-reaching fiscal consequences on future state government operations.[2] From an ideological standpoint, reducing government spending and encouraging private sector earnings and investment may be desirable. From a purely economic perspective, however, state spending of these foregone revenues would have a significantly larger economic impact in Alaska than ELF-induced oil company investments at Prudhoe Bay and Kuparuk.

Proponents of the existing ELF formula claim that it has produced 800 direct drilling jobs and 1,600 additional indirect and induced jobs in support services and other sectors of the economy. Note that the DOL employment figures cited above do not support this assertion, at least in terms of direct employment. According to the DOL, the oil and gas industry

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[2]The oil companies say the application of the ELF to Prudhoe Bay and Kuparuk will result in a 7 percent reduction in state revenues, while the Office of Management and Budget (OMB) calculates the reduction at 8 to 14 percent.

in Alaska ranks first in the total amount of wages paid to nonresident employees and fourth among industries with the largest number of nonresident employees.[3] Approximately 21 percent of oil and gas industry employees in 1986 were nonresidents. As the OMB has shown in their ELF analysis, only about 18 percent of oil companys' cash flow from North Slope operations is reinvested in Alaska.[4] The rest leaks out of the state economy.

As an example of the disparity between the economic impact of state revenues vs. ELF-induced investment, consider that $150 million in revenues applied to the personal services category of the state operating budget could fund about 3,000 direct state jobs, while oil company expenditure of $150 million has resulted in 800 direct jobs (claimed by the oil companies) but no additional drilling jobs verified by the DOL. Virtually all State employees would be residents who would spend their wages within Alaska in turn producing indirect and induced benefits to the economy.[5]

Revenue and Profit from the TAPS

Eight pipeline companies (all of which are subsidiaries of major oil companies) own the TAPS: Amerada Hess Pipeline Corp., Arco Pipelines Co., BP Pipelines, Inc., Mobil Alaska Pipeline Co., Phillips Alaska Pipeline Corp., Sohio Pipeline Co., and Union Alaska Pipeline Co. Alyeska Pipeline Service Company operates the TAPS for the owners. Roughly 94 percent of Alaska oil production is shipped via the TAPS.[6]

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[3]"Nonresidents Working in Alaska in 1986," Alaska Department of Labor, January 1988, p. 10.

[4]"The ELF: A Policy Perspective," pp. 13, 18.

[5]According to the "Statistical Quarterly," (various issues) published by the DOL, the average state employee wage in FY 87 was $34,602 plus $7,779 in benefits and 3,720 in insurance ($46,100 total compensation package).

[6]House Research Memorandum 87.132, March 6, 1987.

Each pipeline company charges a separate tariff, which on a consolidated basis currently averages $3.20/bbl. of throughput according to the Petroleum Intelligence Weekly (PIW).[7] At an average daily throughput of approximately 2 million barrels, the TAPS owners presently receive revenues of about $6.2 million per day or $2.26 billion per year. The PIW estimates pipeline profits at $0.43/bbl. or $860,000 per day ($314 million per year). Using information supplied by the Alaska Public Utilities Commission (APUC), we estimate that pipeline operation between 1977 and 1986 (the most recent year for which data are available), produced $30.35 billion in gross operating revenues on total throughput of 5.12 billion barrels. According to the APUC, the pipeline owners have spent about $26.9 billion to build, operate and maintain the TAPS through 1986.[8] On a cumulative basis, TAPS gross operating revenues appear to have first exceeded estimated expenses in 1984.[9]

Revenue and Profits from Tanker Operations

Approximately 40 percent of domestic tanker tonnage in the Alaska trade is owned by oil companies; the remainder is chartered.[10] Among the oil companies, there is a wide variance in the amount of proprietary tonnage versus chartered tonnage. Standard Oil for example, must charter its entire tanker requirements because it is controlled by a foreign company (British Petroleum), which cannot own U.S. flag tonnage under provisions of the Jones Act. According to the PIW, the average shipping cost via tanker from Valdez to the West Coast (Puget Sound, San Francisco and Los Angeles) is $0.99/bbl. and to the Gulf Coast (including an $0.80/bbl. Panama Pipeline tariff) is $3.35/bbl.

In its netback calculations of oil company revenues for severance and income tax purposes, Department of Revenue (DOR) allows oil companies to charge a tanker transport tariff equal to operating expenses plus a profit margin of two percent over inflation. This translates into a current profit margin of approximately six percent.[11] Thus, if we assume a TAPS throughput of two million barrels per day, with 60 percent going to the West Coast and 40 percent to the Gulf Coast, oil companies have estimated total revenues of $3.23 million per day ($1.18 billion per year) and profits of about $193,200 per day ($70.52 million per year) from their tanker operations.

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[7]February 1, 1988, p. 2.

[8]"Eighteenth Annual Report to the Legislature," Alaska Public Utilities Commission, February 15, 1988, p. 86.

[9]House Research Agency Memorandum 87.132.

[10]"Report to Congress on Alaskan Oil," U.S. Department of Commerce, June 1986, p. II-26.

[11]Roger Marks, DOR Economist, personal communication, April 1988.

Panama Pipeline Revenues and Profits

The Trans-Isthmian oil pipeline across Panama began operation in October 1982. The pipeline has an average maximum capacity of 800,000 barrels per day and is a joint public-private venture with the Government of Panama (through Cofina, the National Finance Corporation) at 40 percent equity; Northville Terminal Corporation (U.S.) at 38.75 percent equity and Chicago Bridge and Iron Industries (U.S.) at 21.25 percent equity.[12] The original investment amounted to $347.7 million, which was apparently paid off by mid-1986. The Panamanian government estimates that the pipeline has a total domestic economic impact of 700 jobs and $150 million in gross revenues per year.

Using the $0.80/bbl. tariff charge cited previously and assuming 800,000 barrel per day throughput, the pipeline generates an estimated $233.6 million in gross annual revenues for the owners. We do not have figures on annual operating costs and thus have no means to calculate pipeline profits.

Comparison of Petroleum Taxes and Royalties

Comparing effective petroleum tax rates among states is not a straightforward exercise, as they rely on different tax instruments to generate revenues. For example, Texas has a lower severance tax rate than Alaska but charges a much higher royalty. Table 1 provides a summary of the taxing strategies of the top five oil and gas producing states. A more complete description of the taxing instruments used by these states is included in Attachment B.

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[12] "Report to Congress on Alaskan Oil," p. IV-59.

TABLE 1

STATE TAXES AND ROYALTIES IMPOSED ON OIL & GAS PRODUCTION IN THE TOP FIVE PRODUCING STATES

STATE	PROPERTY TAX	PRODUCTION TAX	OTHER TAX	ROYALTY	CORPORATE INCOME TAX
ALASKA	placed upon oil and gas production and pipeline transportation property—20 mills of full and true value	Oil: 15% of gross value or $0.80 per barrel, whichever is greater, multiplied by the economic limit factor. Gas: 10% of gross value or $0.064 per MCF, whichever is greater, multiplied by economic limit factor	Conservation tax: $.00125 per bbl.	12.5%	sliding scale--over $90,000 @ 9.4%
CALIFORNIA	rates fixed locally	production charge--rate determined annually	Documentary Transfer Tax: transfer of deeds, 55 cents per $500 of value	30%	9.6% of net income derived within the State
LOUISIANA	none	Oil: 12.5% of value Gas: 7 cents per MCF	Natural gas pipeline companies franchise tax: based on gross receipts apportioned to state, 1%	20%-25%	sliding scale--over $200,000 @ 8%
OKLAHOMA	none	Oil and Gas: 7% of gross value	Oil excise: .085 of 1% of gross value per barrel produced. Gas excise: .085 of 1% gross value of gas produced Natural and casinghead gas conservation tax: 7 cents per MCF less 7% of the gross value of each MCF	18.75%	5% of federal income tax
TEXAS	aggregate of local rates	Oil: 4.6 cents per bbl. (not less than 4.6% of market value) plus 3/16 of 1 cent per bbl. Natural Gas: 7.5%. Minimum, 121/1500 of 1 cent per MCF	none	20%-25%	Franchise tax—$5.25 per $1,000 stated capital, surplus, and undivided profits allocated according to gross receipts from intrastate business

The table below compares Alaska's severance tax rates for production from Prudhoe Bay and Kuparuk under the present and proposed ELF formulae with those of four other oil producing states:

State	Severance Tax Percent of Value	Severance Tax Per Barrel
Wyoming	13.0 percent	$2.02
Louisiana	12.5	1.94
Oklahoma	7.0	1.08
Texas	4.6	0.71
Alaska (Prudhoe Bay proposed)	14.8	1.26
Alaska (Prudhoe Bay existing)	12.3	1.05
Alaska (Kuparuk proposed)	11.9	1.04
Alaska (Kuparuk existing)	8.0	0.62

Source: "The ELF: A Policy Perspective," pp. 21, 22.

* * *

It is important to look at the severance tax on both a percentage and a per barrel basis. Since production from the North Slope occurs on a vastly larger scale and has a much lower wellhead price of oil than some other states with comparable percentage rates, Alaska's severance tax per barrel tends to be lower.

Another important factor to consider when comparing tax rates among various states is their relative dependency on oil and gas revenues. In FY 88, petroleum revenues will account for 84 percent of total Alaska state revenues, while the next largest oil producer--Texas--is only about 20 percent dependent on oil and gas revenues.[13],[14] After the precipitous drop in oil prices in 1986, several of the other oil producing states moved to broaden their tax bases and reduce their dependency on oil and gas revenues. For example, Texas enacted a $5 billion state sales tax; the largest state tax increase in U.S. history. Alaska has not chosen to broaden its revenue base, which makes state government operations and fiscal management increasingly vulnerable to fluctuations in petroleum revenues.

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[13]"March 1988 Revenue Forecast."

[14]April 27, 1987 Memorandum from Hugh Malone, DOR Commissioner to Governor Cowper regarding Senate President Jan Faiks' Memorandum of April 10, 1987 on Oil and Gas Tax Reductions in Other States, p. 6.

Terms of the TAPS Tariff Settlement

The TAPS owners filed their original pipeline tariffs with the federal Interstate Commerce Commission (ICC) in mid-1977. The tariffs ranged from $6.04/bbl to 6.44/bbl, with a weighted average rate of $6.20/bbl.[15] The State of Alaska, U.S. Department of Justice, Arctic Slope Regional Corporation, and ICC staff immediately filed protests which sought a suspension of the TAPS owners' tariffs and an investigation of their lawfulness. Under the Interstate Commerce Act, the ICC was empowered to determine and prescribe "just and reasonable rates" and correct discriminatory rates.

The state's interest in lower tariff rates was primarily financial; severance tax and royalty revenues are based on wellhead value--market price less costs of transportation to markets. The wellhead value is lower when pipeline tariffs are high. The state had a secondary interest in lower tariffs in order to encourage new oil development on the North Slope, particularly of marginal fields that might otherwise be uneconomical under higher tariffs. Additional crude oil production would increase state tax and royalty revenues.

The U.S. Department of Justice (Antitrust Division) was interested in resolving a longstanding debate on oil pipeline ratemaking methodology. The department also felt that there should be some refund policy or an adjustment of methodology in lieu of refunds. The Arctic Slope Regional Corporation (ASRC) views the TAPS as a crucial component to its aspirations as a future North Slope producer and crude oil shipper. Thus, lower tariff rates are in ASRC's best interest, particularly in the 1990s and beyond.

In the estimation of the Department of Law, the TAPS case was the most costly and complicated litigation in U.S. history. The eleven-year saga of the TAPS case and an outline of the final settlement terms are included in Attachment C. Table 2 shows the additional state revenues collected under the terms of the TAPS settlement through 1988. Figure 1 shows TAPS tariffs under the settlement methodology (TSM) through 1991. This graph depicts one of the state's major objectives in the tariff dispute--to defer revenues into the 1990s and encourage increased oil company investment on the North Slope. This is accomplished by allowing a larger near-term tariff rate, which lowers the state's near-term royalty and severance tax revenues, and a lower tariff rate in the 1990s. The TAPS owners were interested in maximizing near-term income and therefore were amenable to the basic principles of the agreement.

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[15]House Research Agency Memorandum 85.175.

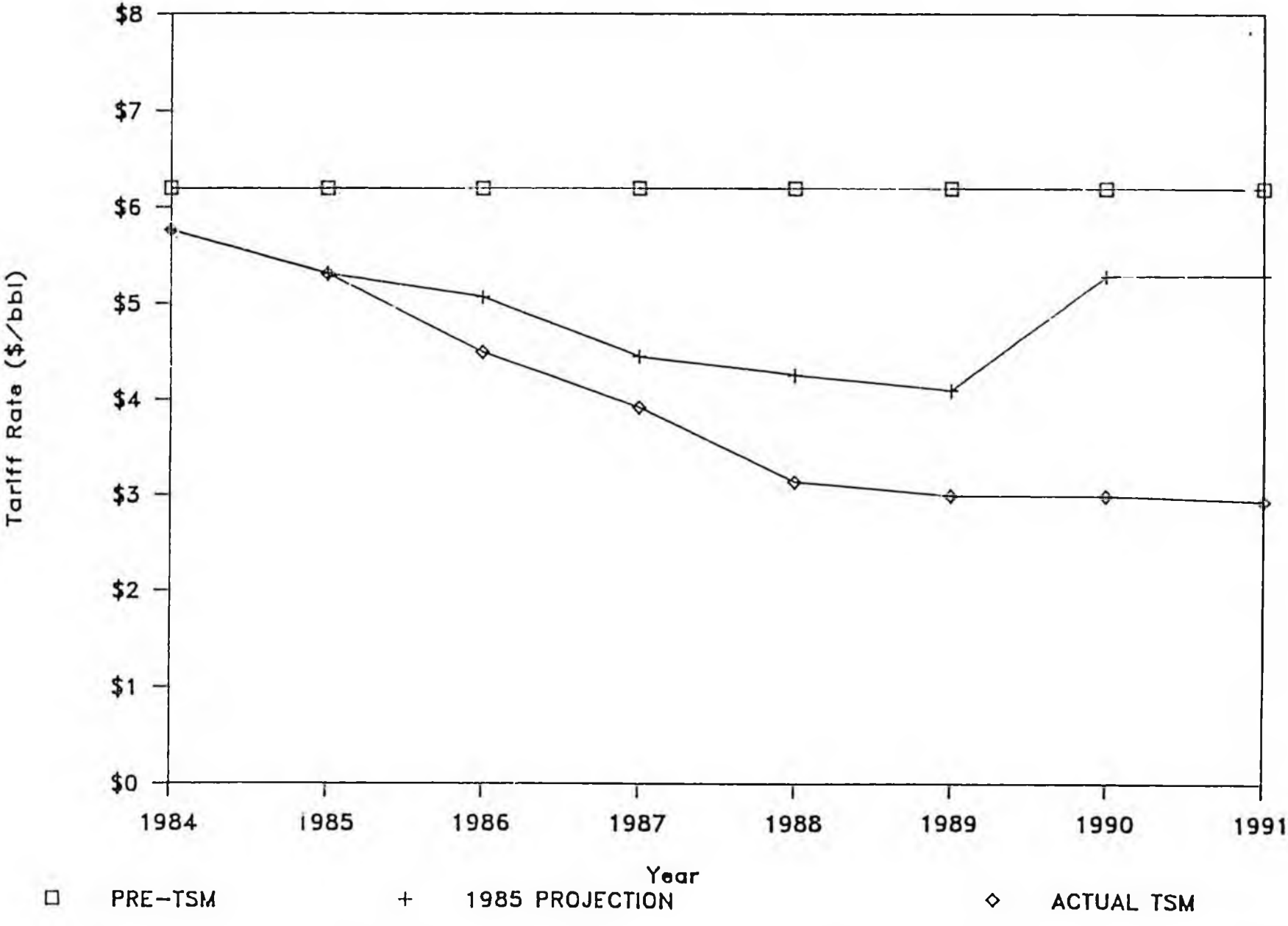
TABLE 2

ADDITIONAL REVENUES COLLECTED BY
THE STATE OF ALASKA
UNDER THE TAPS SETTLEMENT AGREEMENT
THROUGH 1988
($ millions)

	Resulting from Refunds	Resulting from Lower Tariffs	Total
Additional Royalties			
In-kind	$ 69.59	$ 384.29	$ 453.88
In value	38.82	273.55	312.37
Total Royalties	$108.41	$ 657.84	$ 766.25
Additional Production Taxes	$108.77	$ 587.96	$ 696.73
Reimbursement of Litigation Expenses	33.28	.00	33.28
TOTAL	$250.46	$1,245.80	$1,496.26

FIGURE 1

TAPS TARIFFS (1984–1991)



The Department of Law felt that the terms of the TAPS settlement were as good as the state could expect without further litigation, which might be decided against the state. The Department of Law estimates that the settlement will eventually allow the state to realize about 64 percent ($4.5 billion of $7 billion in 1985 dollars) of potential contested revenues. The basic tradeoff the state made was in favor of greater revenue certainty against the anticipated delay and expense of further litigation and the risk of an unfavorable outcome in court.

For the oil companies, the terms of the TAPS settlement allowed them to earn an additional $2.5 billion (1985 dollars) in gross revenues they might not have received under an unfavorable court settlement for the price of their own legal fees plus the $33 million in litigation expenses they had to reimburse the state.

* * *

I hope we have provided enough information for your purposes. Please call if you have questions.

Attachments

ATTACHMENT A

Oil Drilling Firm Staffing Patterns

MEMORANDUM State of Alaska

TO: Brad Pierce
House Research Agency

Thru: Sally Saddler
Research Supervisor

FROM: Brynn Keith
Labor Economist
AK Dept. of Labor

DATE: April 21, 1988

FILE NO:

TELEPHONE NO: 465-4500

SUBJECT: Oil Drilling Firm Staffing Patterns

The attached information reflects the staffing patterns of oil drilling firms operating in the North Slope Borough. Data have been compiled for the fourth quarter of 1986 and the fourth quarter of 1987. These data reflect the same group of oil drilling firms represented in the Governor's ELF report.

Occupational data were taken from reports employers file quarterly with the Alaska Department of Labor.

Occupational information is based on the Standard Occupational Classification structure. This system was designed by the U.S. Department of Commerce and is widely used by both federal and state agencies.

The response rates for drilling firms with North Slope activity are low. North Slope drilling employment is estimated at 548 workers for the fourth quarter of 1986, 325 (59.3%) are represented in the attached. Similarly, an estimated 501 workers were employed on the Slope during the fourth quarter of 1987. Occupational and geographical information was reported for 322 workers for the fourth quarter of 1987, or 64.3% of all drilling workers on the North Slope.

cc: Chuck Caldwell
Frank Spargo
Kathy Thomas
Jeff Hadland

OCCUPATIONAL DISTRIBUTION IN OIL DRILLING FIRMS
NORTH SLOPE BOROUGH
1986 Q4 & 1987 Q4

OCCUPATION	86Q4 % OF TOTAL	87Q4 % OF TOTAL
Computer Analyst	1.2	0.0
Construction Manager	0.0	0.3
Cook	0.0	4.0
Crane/Tower Operator	1.2	0.0
Drillers, Oil	27.1	24.8
Electrician	4.6	3.1
Excavating/Loading	0.0	1.2
Extract Occs, NEC	25.2	32.3
Heavy Equip Mech	0.6	0.0
Helpers Extractive Occ	2.2	0.0
Helpers Mach Op Assis	0.6	0.0
Indust Mech Rep	4.0	3.7
Indust Truck/Tractor	2.8	0.0
Janitor/Cleaner	0.0	1.6
Mach Maint	1.2	2.8
Managers Food Service	0.0	0.6
Manager Well Drilling	1.5	1.9
Misc Material Moving	5.8	6.2
Mixing Machine Op	4.0	3.7
Separating Mach Op	0.3	0.0
Stationary Eng	1.2	1.9
Supv Extractive Occ	4.3	2.2
Truck Driver Heavy	6.8	3.4
Water/Sewage Plant	0.0	1.2
Welder	4.3	5.0
TOTAL WORKERS	325	322

Source: Alaska Department of Labor, Research & Analysis

ATTACHMENT B

Description of Petroleum Taxing Regimes in the Five Top Producing States

ATTACHMENT B

Alaska

Property Tax. Alaska's principal minerals of commercial significance are exempt from ad valorem property taxes. Although no statewide property tax exists, a tax is imposed upon oil and gas exploration production and pipeline transportation property in lieu of local taxes upon oil and gas property.

Production Tax. The tax rate for oil is 15 percent of gross value (12.25 percent for the first five years of commercial production from a lease or property coming into commercial production after June 30, 1981 and 15 percent thereafter) or $0.60 per barrel of old oil ($0.80 for other oil) adjusted by a factor related to the specific gravity of the oil. The tax rate for gas is 10 percent of gross value or $0.064 per MCF (thousand cubic feet). The rates on both oil and gas are multiplied by an economic limit factor which is designed to reduce the tax rate as production volumes relative to production costs decrease.

Oil and Gas Regulation and Conservation Tax. A tax of $0.00125 is imposed on the producers of oil for each barrel of oil removed or sold from each lease or property in the state.

Royalty. The State's royalty share is 12.5 percent, or one-eigth.

Corporate Income Tax. The corporate income tax is based upon a sliding scale--taxable income over $90,000 is taxed at a rate of 9.4 percent. The taxable income base for oil and gas corporations is determined differently than other corporations.

California

Property Tax. Property taxes are limited to one percent of the property's 1975-1976 valuation and do not increase more than two percent in annual valuation unless the property is sold. The rate is fixed locally to meet budget needs. The market value of producing oil and gas mineral property is determined by estimating the value of the volumes of proven reserves, which are those reserves that geological and engineering information indicate with reasonable certainty to be recoverable in the future.

Oil and Gas Production Charges. The production charge rate is determined annually by the Department of Conservation based on an estimate of the amount of funds that will be necessary to carry out the provision of the state's oil and gas conservation laws.

Documentary Transfer Tax. A tax is imposed by counties and cities on each deed, instrument or writing on lands or other realty which are within a county and are transferred to a purchaser--a tax on the value or purchase prices equal $0.55 for each $500.

Royalty. The royalty is 30 percent for oil and gas produced on state land.

Corporate Income Tax. The corporate income tax is a direct tax on net income (derived from sources within the state) of corporations not taxable under the Bank and Corporation Franchise Tax Act at the same rate as the franchise tax--9.6 percent of net income derived from business transacted in California.

Louisiana

Property Tax. The Louisiana Constitution exempts the state's commercially most siginificant minerals, oil and gas, from any taxes except severance taxes.

Production Tax. Oil is generally taxed at the rate of 12.5 percent of its value at the time and place of severance--which is the greater of the gross receipts received from the first purchaser less trucking, barging, and pipeline fees or the posted field price. Gas is generally taxed at the rate of $0.07 per MCF. Reduced rates are provided for less productive oil and gas wells.

Royalty Gas Excise Tax. A royalty gas excise tax is levied on each person producing gas in the state equal to the difference between the price received by the producer for the royalty owner's interest in the products and the price actually paid by the producer to the royalty owner.

Royalty. The royalty for oil and gas produced on state land varies between 20 and 25 percent.

Corporate Income Tax. The corporate income tax is base upon a sliding scale--net income in excess of $200,000 is taxed at eight percent.

Oklahoma

Property Tax. Most mineral property is exempt from ad valorem taxation.

Production Tax. Oil and gas is taxed at the rate of seven percent of the gross value of production, which means the gross proceeds realized from the first sale of such production including the cash value and all premiums otherwise given to or reserved for the producer and all interest owners of the production without any deduction for cost whatsoever.

Oil and Gas Excise Tax. In addition to the gross production tax, the state imposes excise taxes on oil and gas subject to the gross production tax at the rate of 0.85 percent of the gross value of the oil or gas produced.

Conservation Excise Tax. The state imposes a conservation excise tax on the severance of natural and casinghead gas. The amount of the tax is $0.07 per MCF less seven percent of the gross value of each MCF.

Royalty. The royalty is 18.75 percent for oil and gas produced on state land.

Corporate Income Tax. The corporate income tax is five percent of the federal taxable income with adjustments.

Texas

Property Tax. Minerals in place, and separate interest in such property are generally subject to ad valorem taxation at their fair market value. The taxation rate is fixed locally to meet budget needs.

Production Tax. The tax rate on oil is 4.6 percent of the market value or $0.046 per barrel, whichever results in a greater amount of tax. The rate for gas is 7.5 percent of the market value of gas and liquid hydrocarbons other than condensate.

Crude Petroleum Tax. Texas imposes a tax of 3/16 of $0.01 on each barrel of crude petroleum produce in the state.

Royalty. The minimum royalty for oil and gas produced off-shore of state land is 25 percent and the average on-shore royalty is 20 percent.

Corporate Income Tax. The state does not have a corporate income tax. A franchise tax of $5.25 per $1,000 stated capital, surplus and undivided profits allocated according to gross receipts from intrastate business is levied.

ATTACHMENT C

History of the TAPS Case Outline of
the TAPS Settlement

1/28/88
House Resources Committe
Briefing

KEY EVENTS IN OIL PIPELINE RATEMAKING

Date	Event
1906	Hepburn Act passed; subjects oil pipelines to regulation under the Interstate Commerce Act.
1940-1944	Interstate Commerce Commission (ICC) employs the "valuation" methodology in three cases concerning the reasonableness of oil pipeline rates; these are the only pre-Williams cases that address the reasonableness question.
1941	Atlantic Refining Consent Decree entered, settling antitrust litigation. Decree limits pipeline company dividends to 7% OF ICC valuation.
Dec. 1971	Shippers protest Williams Bros. Pipe Line rates with the ICC.
June 1974	Administrative Law Judge (ALJ) upholds Williams rates.
Nov. 1975	ICC affirms ALJ decision in Williams. Case is appealed.
June 1977	Alaska (and others) protest TAPS rates with the ICC.
Oct. 1977	Jurisdiction over oil pipelines transferred from ICC to newly-created Federal Energy Regulatory Commission (FERC).
June 1978	On FERC's request, Court of Appeals remands ICC's Williams decision to FERC and orders FERC to "develop a viable precedent for oil pipeline ratemaking." (The Court of Appeals decision is referred to as Farmers Union I.)
Feb. 1980	ALJ issues decision on methodology issues in TAPS (Phase I); specific ratemaking issues are reserved for a subsequent hearing (Phase II).
July 1980	FERC hears oral argument concerning TAPS Phase I decision.
Feb. 1981	Alaska (and others) file a motion with FERC requesting a decision in TAPS (Phase I). Motion is denied.

Date	Event
June 1981	Shippers ask the Court of Appeals to order FERC to decide the Williams case (Phase I). FERC pledges to do so by Fall 1981 and the shippers' request is dismissed.
Feb. 1982-Dec. 1984	ALJ holds hearings in TAPS (Phase II).
March 1982	Alaska receives TAPS settlement offer from BP.
May 1982	Alaska Legislature informs Governor Hammond that it believes the State should reject the BP settlement offer and continue the Phase I litigation because of concerns over developmental effects on the North Slope and the relatively short length (10-years) of the proposed agreement. Alaska files a motion with FERC requesting an expedited decision in TAPS (Phase I).
July 1982	FERC denies motion for expedited decision in TAPS saying its order in Williams will be accompanied by an order in TAPS.
August 1982	Seeing no FERC action in Williams, shippers file suit in District Court; Court orders FERC to decide Phase I in 60 days.
Nov. 1982	FERC issues Williams (Phase I) decision -- Opinion 154. FERC remands TAPS (Phase I) to ALJ for hearings on whether the Opinion 154 methodology should be applied to TAPS.
Jan. 1984-Feb. 1984	ALJ holds TAPS (Phase I Remand) hearings.
March 1984	Court of Appeals remands Williams case to FERC, holding that the methodology adopted in Opinion 154 is inconsistent with the agency's mandate under the Interstate Commerce Act. (The Court of Appeals decision is referred to as Farmers Union II). Alaska (and others) file motion requesting FERC to decide Phase I of TAPS (on the ground that Farmers Union II has made the Phase I Remand moot). FERC takes no action.

Date	Event
Sept. 1984	Alaska engages in TAPS settlement negotiations with ARCO and BP; it also has contacts with Exxon and Sohio.
Nov. 1984	Alaska reaches handshake agreement with ARCO that settles Phase I and Phase II of TAPS.
Dec. 1984	U.S. Department of Justice approves Alaska-ARCO settlement agreement in TAPS.
Jan. 1985	Williams parties submit settlement of Phase II to FERC.
	Alaska (and others) protest Kuparuk rates with FERC.
Feb. 1985	Alaska and ARCO sign the TAPS settlement agreement.
March 1985	FERC approves the Williams Phase II settlement.
April 1985	BP joins the TAPS settlement; the settlement. is filed with FERC.
June 1985	Exxon, Mobil and Union join the TAPS settlement; the settlement is refiled with FERC.
	FERC issues its decision in Williams (Phase I) -- Opinion 154-B.
July 1985	Phillips joins the TAPS settlement.
Aug. 1985	ALJs certify TAPS settlement to FERC.
Oct. 1985	FERC approves TAPS settlement as to signatory parties; remands the case to ALJs with respect to non-signatory parties.
	Alaska (and others) protest Milne Point rates with FERC.
Dec. 1985	FERC issues its decision on rehearing in Williams -- Opinion 154-C. (No appeal is taken from Opinions 154-B and C.)
Feb. 1986	Sohio and Amerada Hess join TAPS settlement agreement; amendment to the agreement is filed with FERC.

Date	Event
April 1986	ALJs certify Sohio-Amerada Hess amendment to FERC.
June 1986	FERC approves Sohio-Amerada Hess amendment to TAPS settlement agreement.
Oct. 1986	FERC dismisses Milne Point investigation on motion of parties.
Nov. 1986	Kuparuk hearings held before FERC ALJ.
Sept. 1987	Alaska (and others) protest Endicott rates with FERC.
Oct. 1987	Court of Appeals rejects Arctic Slope Regional Corporation (ASRC) challenge and affirms FERC approval of the TAPS settlement.
Jan. 1988	Court of Appeals denies ASRC request for rehearing in the TAPS case.

Dept. of Law
1/10/85

OUTLINE OF TAPS SETTLEMENT

HAVE REACHED AN AGREEMENT WITH ARCO

Final document in next 3-4 weeks
Not all companies on board
Numbers are if all join up

TAPS TARIFF DIRECTLY AFFECTS ANS WELLHEAD PRICE

Severance tax and royalty on wellhead
No market at wellhead
Decrease in tariff directly increases wellhead
We get 25-30% of wellhead increase from state lands

REVENUE CONSEQUENCES TO STATE - CHART I AND GRAPH

$2.9 billion more than currently forecast ($2.14 billion in 1985$)
Annual amounts gained (millions)

	Calendar	Fiscal
1985	$233.0	
1986	$153.6	$309.8
1987	$200.4	$177.0
1988	$232.3	$216.4
1989	$256.2	$244.3
1990	$261.7	$259.0
1991	$235.7	$248.7

Effective date of settlement would be January 1, 1986
Tariffs would drop in 1985 by 72 cents, and continue to drop in later years, both in real and nominal terms CHARTS II AND III AND GRAPHS

PRINCIPLES OF SETTLEMENT

1) State wants to defer revenues to 1990's
   A constant dollar in the 1990's is worth the same to the state as that same dollar today
2) Encourage development of ANS reserves in 1990's
   Prudhoe and Kuparuk already on stream with present tariffs
   Low 1990s tariffs will encourage places like Beaufort, native lands and other fields where production might not otherwise be economic
   Certainty now aids economic planning for 90's - litigation makes planning uncertain

MEMORANDUM State of Alaska

TO: Tax Policy Committee

DATE: September 16, 1986

FILE NO.:

THRU:

TELEPHONE NO.: 465-2302

SUBJECT: Severance Tax (AS 43.55)

FROM: Richard D. Monkman
Deputy Commissioner, Taxation

Attached is a memorandum which discusses some policy considerations behind the severance tax, written several years ago by former Assistant Attorney General Jon K. Tillinghast. Of particular interest is the memorandum's historical perspective on resource development in Alaska.

RDM:mkw

Attachment

cc: Royce Weller

ALASKA OIL SEVERANCE TAX POLICY

Alaska Department of Law: Juneau, Alaska
Jon K. Tillinghast, Asst. Atty. Gen.

Each day, some 1.57 million barrels of oil are drawn from the Sadlerochit and Kuparuk reservoirs which underly Alaska's Arctic coast. The oil is passed through the Trans-Alaska pipeline to the port of Valdez, and shipped by tanker to refineries along the Pacific coast and Gulf of Mexico. North Slope oil is the consummate asset in Alaska's economic portfolio. It builds schools in the villages of the Bering Sea: it saves lives in hospitals on the Arctic rim. And, as each tanker departs Alaska's territorial waters, the day when it will be gone draws nearer. In 15 years, North Slope production, including likely new discoveries, will probably be about half of what it is today.

For 250 years, Alaska has known brief and furious interludes of intensive natural resource development. In the main, however, Alaska's history has been one of poverty, stagnation and aftermath. Each profiteer who has dipped into Alaska's resource coffer has paid little for his reward, and has left to those who remained the consequences of his exploitation.

In the beginning, it was the Russian fur merchant. Between 1797 and 1821, the Russian American Co. took of Alaska's waters some 1,3000,000 fur seals and sea otters. Having rendered the sea otter apparantly extinct, the company left as its legacy not only barren waters, but a

diseased Aleut native population which stood at 12,000 in 1780, but numbered 2,200 sixty years hence.

The whalers came next, and after them the miners and fishermen. Each had their golden age--an age about as long as the life of an oil field--and each left behind remains as sad as those bestowed by their Russian predecessors.

Alaska's lot is such that it's economy will always be vulnerable to cycles. It is remote; it is inaccessible; and its weather and its terrain are hostile. For the foreseeable future, the state cannot expect a self-sustaining economy rooted in manufacturing or agriculture. Eight percent of Alaska's work force is involved in manufacturing, most of that being associated with raw processing of fish, timber and oil. The value of agricultural production in Alaska was only $5.5 million in 1960, and had increased to but $9 million by 1979.

Recurring and stable economic development in the extraction of Alaska's natural resources is limited by both the carrying capacity of the resource, and the extraordinarily high costs associated with any economic activity in the state. Although Alaska's commercial fisheries have recovered from the aftermath of systemmatic overfishing in pre-statehood years, that recovery has been achieved only by freezing the level of commercial gear through the state's limited entry legislation, and an aggressive state-funded hatcheries program. Timber

production peaked in Alaska in 1973, when 655 million board feet were harvested from the state's public lands. In 1979, some 493 million board feet were cut.

Alaska's mining industry --for minerals other than oil, gas and gravel--produced $17 million in minerals in 1959, and essentially the same amount in 1979. In 1976 (the last available data year), the per-square-mile valuation of hard rock mineral production in the eleven contiguous western states was $5,545. In Alaska it was $410, and decreased to $284 in 1979.

Regardless of the growth potential in Alaska's base industries--and in many cases that potential is substantial--the cumulative benefits of all recurring economic activities will not sustain a state which, even during the flush of oil revenue, faired poorly with its sisters in the provision of basic services and facilities. For example, Alaska has less than half the national average of hospital beds per capita. The state has .64 nursing home beds per 100,000, compared to the national average of 4.89. 17 percent of Alaska's homes are substandard or overcrowded, as opposed to a national average of 7.7%. The U.S. Environmental Protection Agency estimated in 1980 that it would require per capita expenditures of $783 to bring Alaska's publicly owned sewage treatment works to secondary treatment standards. The national average per capita cost was $128, and no other state had per capita costs over $300. Alaska shares honors with Mississipp. for the fewest

physicians per 100,000 residents--78, compared to the national average of 163. Less than one percent of the state's area is accessible by road.

The modest level of tax revenues capable of being generated by Alaska's base economy is the cause of the state's historical inability to achieve equal footing in the provision of rudimentary services. In 1959, the year of statehood, Alaska's tax revenues totalled $25 million. The Trans-Alaska Pipeline commenced operation in 1977. Between 1970 and 1976, per capita state expenditures, adjusted for inflation, remained virtually constant. While all corporations in the state are subject to the same income tax rate, in FY 1981 the state collected $860 million in income taxes from corporate oil producers, and $35 million in income taxes from all other corporate activity in the state.

Because of the backdrop against which it occurred, and the return of a "bust" period which imprudent fiscal management would ensure, no issue has more consumed the Alaska Legislature over the past decade than the establishment of sound tax policy during the brief, intensive and extraordinarily profitable period of oil production in Alaska. State government cannot alter the variations inherent in an extractive economy. However, no motivation more underlay statehood than did Alaska's need to steward the brief periods of intense wealth generation--largely by non-residents--in order to cushion the inevitable prolonged aftermath which Alaskans alone would be required to suffer.

Possessing the essential attribute of statehood--the power to tax--Alaska would be capable of evening the curves by establishing a tax structure which, among of other legal and policy considerations, was responsive to three fundamental concerns:

(1) "Boom" activities, for two reasons, tended to generate substantial profits which were exported in toto and virutally tax free. First, because of the marginal nature of Alaska's base economy, tax liability was of necessity often low. Of perhaps greater importance, the incidence and measure of taxation in Alaska's laws were drawn from experience with the base economy. The "boom activities" could be of a nature for which the incidence and measure of the tax were inappropriate, resulting in under-taxation. For example, the Alaska Legislature found in the mid-1970's that, largely because of the way that Alaska law measured the income of a multi-state corporation doing business in Alaska, the effective tax rate on a multi-state company producing oil in Alaska was about 2 percent, instead of the 9.4 percent paid by local Alaska companies;

(2) The "boom activity" inevitably aggravated the state's existing fiscal deficiencies through inflation and population increases, and the attendant increased needs for public services. In 1970, Alaska's population stood at 302,000. By the completion of pipeline construction in 1977, the state's population had swelled to 396,000. During the pipeline construction year of 1975, the Consumer Price

Index ("CPI") rose 7 percent nationwide. In Anchorage it rose 11.1 percent--although in the pre-construction years of 1967-73 that city's CPI had risen at substantially lower rates than the nationwide average. In 1981, an average American family of four spent $72 per week on food. In Fairbanks it spent $93, and in Barrow $180. Completion of the pipeline in 1977 also left an inevitably high unemployment rate among an artificially high work force. In 1978, Alaska had an 11 percent unemployment rate (the highest in the nation), against a national average of 6 percent; and

(3) The "boom" participants were not merely earning and exporting returns from Alaska's economic portfolio. They were raiding its corpus. And, with little but speculation as to whether there lay hidden future assets of the magnitude of Prudhoe Bay, it was incumbent upon the Alaska Legislature to ensure that the greatest long-term public value was made of this asset before it so soon and so finally evaporated.

Intensive oil exploration in the state began in 1954, when the Bureau of Land Management awarded 272 oil and gas leases covering some one-half million acres. At the time, any oil production would have been subject to the territory's general mining license tax, which was first enacted in 1913, and which levies a progressive 3-7 percent tax on net income from the mining operation.

The commencement of drilling activities under the 1954 leases elicited the territory's first interest in tax

legislation responsive to oil and gas production activities. In 1955, the legislature adopted Alaska's first oil and gas severance tax. Modelled after Oklahoma's statute, the act imposed a tax of one percent on the gross value of produced oil at the wellhead.

On September 29, 1957, Alaska became an oil producing territory with the discovery of the Swanson River oil field in the Kenai National Moose Range. Two years later, Alaska became a state, and thereafter a series of discoveries in upper Cook Inlet clearly entrenched oil production as a major component of Alaska's base economy. The first offshore discovery was the Middle Ground Shoal field in Cook Inlet in June, 1962, followed by the Trading Bay field (June 1, 1965), the Granite Point field (June 9, 1965) and the McArthur River field (October 24, 1965). Coupled with several gas discoveries during the same period, the value of Alaska oil and gas production rose from $301,000 in 1959 to $50.4 million in 1966.

Despite the success of Cook Inlet development--which was to eventually peak in 1970 with the production of some 81.6 million barrels of oil--the Alaska Legislature remained unwilling to increase the industry's severance tax liability above the conservative one percent rate established two years before oil was discovered. Statehood did not bring a rush to tax for taxation's sake, and the health of Cook Inlet activity did not convince the legislature that

oil development was anything other than another tentative component of Alaska's vulnerable base economy.

In 1967, the state finally increased the severance tax from one to two percent--for reasons hardly of its own making. In that year, the city of Fairbanks was devastated by savage floods, and the legislature was called into special session to provide emergency relief. Some $9 million in disaster appropriations were necessary. To fund a portion of the deficit, the legislature temporarily increased the severance tax.

Between 1966 and 1968, Cook Inlet production had expanded from 14 million barrels annually to 66 million barrels. Annual production was worth $187 million in 1968. The 1968 legislature concluded that higher severance tax rates were warranted in light of this swell in industry profitability. The decision was colored by perceived price reporting anomalies by Cook Inlet producers, and the result was an increase in the severance tax rate from one to three percent--plus the one percent disaster severance tax. Severance tax revenues grew the following year from $1.1 to $4 million.

By 1968, then, the state's oil severance tax remained at a level comparable to taxes assessed against even marginal components of the state's base economy. In 13 years, the tax had increased 3 percent from the initial hesitant levy on an unproven industry. In early 1968, however, the largest oil field ever found in the United

States was dicovered at Prudhoe Bay. It was immediately apparant that the brief window of intensive industrial activity heralded by the discovery would dwarf the booms of the past, and that a tax regime conservatively developed in response to Cook Inlet production would not be sufficient to manage the impacts and significance of Prudhoe Bay.

After nearly two years of study and debate, the legislature in 1970 adopted the state's first progressive severance tax rates--although the 1968 increase had been "progressive" in the sense that it was responsive to substantial increases in profitability in the one region where oil development was occurring. The rates established by the 1970 law were:

Daily Well Production	Rate (%)
Up to 300	3
Next 700	5
Next 1500	6
Above 2500	8

Since the 1967 disaster severance tax was repealed, the law had the effect of reducing the nominal rate on marginal wells. Severance taxes in FY 1971 increased from $5.9 million to $9.9.

Severance taxes are based upon value at the well-head--a sum which decreases with any increase in transportation costs to the point of ultimate sale. During the early 1970's, cost estimates for the Trans-Alaska Pipeline grew from $1.3 to $3 billion, and the state became concerned that

what the severance tax gaveth, high pipeline tarriffs imprudently allowed would taketh away.

The legislature's response in 1972 was to establish a combined floor on state royalty payments and severance taxes. The floor was established by applying the applicable severance tax rate, with a credit for royalties, to a wellhead price of $2.65/barrel. The law resulted in only a nominal increase in severance tax revenue in FY 1973-- from $11.4 million to $12 million.

The concept of a combined "floor" on severance taxes and royalties was an anethema to the oil industry. Royalty payments had been set by lease agreement with the state at 1/8 of the value of production--without a price "floor"--and the industry sued the state over the 1972 law as part of wide-ranging litigation dealing with state regulatory authority over pipeline construction and operation.

In 1973, Governor Egan called a special session of the legislature to attempt to settle the lawsuit. The state agreed to repeal the royalty portion of the "floor", and also agreed to repeal or modify a host of pipeline revenue and regulatory measures which the industry found objectionable, but only after the industry agreed to corresponding increases in the severance tax rate. Industry was willing at the time to sacrifice severance tax advantages for a removal of the royalty floor, together with substantial state

concessions in the area of pipeline regulation. The rates established in the 1973 special session were:

Daily Production	Rate
Up to 300	5
Next 700	6
Over 1000	8

The "floor" on the severance tax was retained, with a cents-per-barrel minimum tax established based on applying the applicable rate to a wellhead value of $3.375. The floor was to be adjusted, however, both by the API gravity of the oil, and by increases or decreases in the U.S. Bureau of Labor Statistic's Wholesale Price Index for crude oil.

The 1973 "package" was in fact a miscalculation by both sides. Neither side foresaw the Yom Kippur war months hence; the resultant embargo; the quadrupling of OPEC prices; and the imposition of federal price controls. The industry found the cents-per-barrel floor increasing through the WPI while federal price controls capped the value of "old" Cook Inlet oil. The legislature, on the other hand, was faced with potentially skyrocketing Prudhoe Bay profits, with only a 3 percent rate change separating the most profitable Prudhoe Bay operation from the most marginal well in Cook Inlet.

The sessions of the legislature between 1974 and 1978 were consumed with the controversy of oil industry taxation. In-depth studies were undertaken of the likely

profitability of Prudhoe Bay production, with an eye toward equalizing the impact of the severance tax on the state's producing regions, and evening out the boom-bust curve threatened by North Slope production. Information developed for the legislature suggested that Prudhoe Bay production would yield a 35 percent rate of return. The existing severance tax law, in short, was insufficiently progressive.

In 1977, the legislature fundamentally altered the state's severance tax. A single nominal rate of 12.5 percent was established. That rate, however, was reduced by a fraction called the "economic limit factor" ("ELF"). The ELF fraction had the effect of reducing the nominal rate as production from a well decreased, to the point where no tax was imposed when a well operated at its minimum economic limit.

The ELF fraction is a unique feature of Alaska's severance tax, and reflects the legislature's sensitivity to the very different circumstances of northern and southern oil development in the state. Cook Inlet production began to decline after 1970. As a well's productivity declines, the point approaches when production from the well is no longer economically justified. Near that level, even a very small flat rate severance tax will cause the well to be shut-in. The ELF fraction is thus not only consistent with principles of progressive taxation, but as well performs a critical conservation function. In Cook Inlet today, the average "ELF factor" is 30 percent, which means that the

average effective severance tax rate is 5 rather than the current nominal 15 percent. Numerous wells are currently operating at or near their minimum economic limit, which means that the effective tax rate for those wells is at or near zero.

The 1977 law also retained the cents-per-barrel floor, raising it to a base of $4.90/barrel for "old" oil and $6.53/barrel for all other oil. The floor was no longer indexed to the WPI.

As discussed previously, the adverse economic impacts and population increases caused by the North Slope boom peaked in the mid-1970's. Alaska's population grew by 10 percent in 1974, and again in 1975, as Trans-Alaska pipeline construction commenced. And even though real state spending per-capita remained virtually constant over that period (see above), the legislature found itself in 1975 with a $450 million revenue shortfall for the period 1975-77. Although increased demands for government services were substantially attributable to pipeline activity, revenues from North Slope development would not be received until the pipeline was completed. Thus, in 1975, the legislature was compelled to enact a two-year "reserves tax." The tax was levied on the value of the oil in the ground, and the tax paid was subsequently credited against later severance taxes.

The two-year reserves tax generated $494 million in revenues It also served to substantially reduce

severance tax payments in fiscal years 1978 and 1979--the first two years of pipeline operation.

The changes made by the Alaska Legislature to the severance tax in the 1970's were the product of a considered effort to make state oil tax policy responsive to the rapidly changing nature, impact and significance of oil production in the state. Although the changes were frequent, they were no more so than the events of the decade which necessitated them. The progressive divergence in the rate of taxation reflected the emergence of Prudhoe Bay as a uniquely profitable enterprise which could in all fairness be subjected to a higher effective severance tax rate with at worst no more severe impact than had been suffered by Cook Inlet operations. The amount of severance taxes imposed on North Slope development was itself influenced by the unquestionably high adverse economic impacts caused by pipeline construction.

The severance tax, however, was not made to pay the price of Prudhoe Bay's role in Alaska's long-term economic goals. To smooth the future economic curve during the brief period of North Slope development, the state, put simply, needed a savings account--a sum above those uncertain revenues which the state's future base economy would yield in order to fund the continuing needs of a population swollen by Prudhoe Bay itself. The state's response was the Permanent Fund--authorized as a constitutional amendment by the voters in 1976, and into

which is placed at least 25 percent of all money received by the state as the lessor of mineral acreage. In Alaska, then, "saving for the future" is a function not of tax policy, but rather of the state's role as proprietor.

In 1981, the state again altered its severance tax laws. As in 1973, it did so in response to oil industry litigation, and the net result was to materially decrease the tax liability on the production industry. As discussed previously, the state's corporate income tax, the fundamentals of which were enacted at the time of statehood, proved an inappropriate measure of a multi-state company's production income attributable to Alaska. In 1978, the legislature amended the income tax to insure that the tax levied on Prudhoe Bay production was at the same rate as that applicable to other taxpayers. The major Prudhoe Bay producers sued the state, seeking to have the income tax declared unconstitutional and some $1.8 billion (collected between 1978 and 1981) refunded.

In 1981, the legislature altered the income tax in order to reduce the state's exposure in the litigation. The amendments, however, substantially reduced the state's income tax receipts. In order to partially compensate for the lost revenues, the nominal severance tax rate was increased to 15 percent, and the ELF discount was disallowed for the first 10 years of production for highly productive wells.

The net result was a decrease in state severance and income tax revenues of some $225 million for upcoming FY 1983--although the decrease was not sufficient to induce the company's to dismiss the income tax litigation.

The fiscal impact of the 1981 package is dwarfed, however, by the current $4-6/barrel drop in world oil prices. Sound fiscal manaegment of Prudhoe Bay must cope not only with the location of the North Slope peak in Alaska's long-term economic continuum, but as well with the yearly and even monthly gyrations in world oil prices. Every $1 drop in oil prices lowers the state's severance tax by 4.5 percent, and has a similar effect on state royalty payments. The severance tax in turn represents about 30 percent of the state's unrestricted revenues.

Much of the popular criticism of Alaska's treatment of the oil industry flows from the events of FY 1982, when OPEC oil prices completed their two year ascension from $12 to $34 per barrel. In FY 1979, with North Slope wellhead values in the $6 range, the state received $1.13 billion in total unrestricted revenues. Total unrestricted state revenues for FY 1982-- the year in which oil prices peaked--were estimated in January, 1982 at $4.13 billion. This year's oil price decreases, however, are now predicted to cause a loss of $1.68 billion in revenues for the remainder of FY 1982 and for FY 1983. Similar drops are predicted for subsequent fiscal years.

AGO 484233

Th results are state revenues for FY 1983 of $2.74 billion--about the same as the $2.5 billion received for FY 1980. The state's flush of oil revenues lasted two years, and the state now finds itself in the position of making massive cuts in both its operating and capital budgets. The state's operating budget will not increase over FY 1982, despite inflation. The FY 1983 capital budget will be approximately one third of the amount authorized in FY 1982.

The response of the legislature has not been to increase oil production taxes. Indeed, with the exception of the 1967 disaster tax, and perhaps the 1975-77 reserves tax, Alaska's policy has been motivated not by monetary reaction, but rather by at least an attempt at principle. Prudhoe Bay is a unique phenomenon played out on an equally unique economic stage. Its astounding magnitude and profitability; its stark contrast in kind and degree to the state's marginal base activities on which Alaska's tax laws are otherwise based; and its fleeting presence on an otherwise depressed frontier, call for the development of tax policies that might seem inappropriate in other times and places. That, however, is the fulcrum of federalism, and it is our federal system which has allowed Alaska to intelligently manage this brief and consequential episode in its very difficult history.

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

March 3, 1987

The Honorable Ben Grussendorf
Speaker of the House
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Representative Grussendorf:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill relating to the oil and gas properties production tax The primary effect of the bill is to postpone the application of the "true" economic limit factor (ELF) to the Prudhoe Bay field. The bill also amends the economic limit factor provisions applying to all oil fields so that the ELF is not sensitive to changes in the value of oil.

Existing AS 43.55.011(a) provides that an oil producer must calculate its production (severance) tax by multiplying the nominal rate calculated under AS 43.55.011(b) and (c) by the economic limit factor determined under AS 43.55.013. The ELF is a formula that has the effect of reducing the severance tax rate. In 1981, the legislature made several changes in oil and gas taxes: the income tax was changed to substitute modified apportionment for separate accounting; the nominal rate of the severance tax was increased for some fields; and the application of the ELF to a lease or property with an ELF of more than .7 was suspended until after that lease or property had been in commercial production for 10 years. Ch. 116, SLA 1981. Suspension of application of the ELF was accomplished by providing that, if the ELF was more than .7, then the ELF was considered to be "one." AS 43.55.013(b)(3). Thus, when multiplying the severance tax rate by the ELF, the full amount of the tax is the product.

Only the Prudhoe Bay and Lisburne fields currently have an ELF greater than .7. The Lisburne ELF is expected to fall below .7 after fiscal year 1988, but the Prudhoe Bay ELF is expected to remain about .7 for a number of years. Prudhoe Bay will have been in production for 10 years in June, 1987; thus, absent an amendment to AS 43.55.013(b)(3), the "true" ELF, as calculated under AS 43.55.013(b)(1), will begin to apply to that field at that time.

The fiscal note on the 1981 legislation did not include projections beyond FY 1985, but an analysis by the Legislative Finance Division showed that application of the "true" ELF provision would cause state revenue to fall precipitously in FY 1988. Governor Hammond noted this possibility, but expressed "full confidence in the ability of the legislature to deal at that time" with adverse revenue consequences, should they prove to be serious. Statement of Governor Hammond on signing FCCSSB 524 (ch. 116, SLA 1981); see July 27, 1981 press release on oil and gas legislation. fourth page.

Application of the "true" ELF to Prudhoe Bay would result in serious consequences for the state in the coming fiscal year: state severance collections would be reduced by over 15 percent, and FY 1988 revenue would fall by $93,000,000 (already accounted for in the official "mean" forecast). Section 1 of the attached bill would prevent this precipitous decline in revenue by amending AS 43.55.013(b)(3) to delay the applicability of the true ELF to Prudhoe Bay for an additional five years. Section 1 of the bill also makes a conforming amendment to AS 43.55.013(b)(2) and (4). So long as the "true" ELF does not apply, the severance tax rate will be the full 15 percent of value, or $.80 a barrel, whichever is greater, subject to the adjustment in AS 43.55.012.

The bill also changes the ELF provisions for all oil fields to remove the sensitivity of the ELF to price fluctuations. An element of the ELF calculation is the "PEL," or "production at the economic limit." The PEL represents the number of barrels a producer must produce in order to recover the costs of production. Currently, the PEL is presumed to be 300 barrels per well per day, but the taxpayer may rebut this presumption at a hearing before the Department of Revenue. At the hearing, the PEL would be calculated by dividing the cost of production into the value of the oil. AS 43.55.013(d). If the price of oil drops, the producer may be able to prove an entitlement to a PEL in excess of 300 barrels; if so, the ELF for that producer will go down. Thus, if prices fall drastically, the state loses severance tax revenue not only because the severance tax is applied against a lower value of oil, but also because the severance tax rate itself goes down as the result of a PEL hearing. Earlier in 1986, because of low prices, we were faced with the possibility that the state might suffer from this double reduction in severance tax revenue.

Section 2 of the attached bill deals with that problem by repealing the portion of existing law that provides for a hearing to change the PEL. The PEL is then simply set at 300 barrels per day. As a result, the ELF will be sensitive to changes in the amount of production, but will no longer be sensitive to fluctuations in price or the costs of production. Section 3 of the bill repeals two subsections in AS 43.55.013 dealing with the two elements of the hearing: costs and values. These changes to not apply to the production of gas.

I urge your early consideration and passage of this bill.

Sincerely,

Steve Cowper
Governor

No. 1

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST:

Bill Version : HB 164
Publish Date : HOUSE 3/4/87

Revision Date:
Title : An Act Relating to the Oil and Gas Properties Production Tax
Sponsor : Rules/Governor
Requestor : Rules

Agency Affected : Revenue
BRU :
Components :

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						
CAPITAL						
REVENUE		76,730.0	91,950.0	98,480.0	99,850.0	105,610.0

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS : (Attach a separate page if necessary)

SEE ATTACHTED ANALYSIS

Vince K Wright

Prepared by : Chuck Logsdon
Division : Revenue/Research
Phone : 276-5364
Date : March 2, 1987

Approved by Commissioner : Hugh Malone
Agency : Department of Revenue
Date : 3/2/87

Distribution (by preparer):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)
Senate Secretary

Revenue Impact of Extend5 (Million $)

Fiscal Year	Delta 30%	Delta Mean
1987	0	0
1988	76.73	96.26
1989	91.95	118.06
1990	98.48	128.33
1991	99.85	132.92
1992	105.61	139.09
1993	5.73	7.3
1994	3.9	7.64
1995	3.66	6.56
1996	4.55	5.28
1997	3.67	5.55
1998	2.01	3.91
1999	2.53	2.62
2000	-.16	2.08
2001	-.1	2.79
2002	-.82	2.68
2003	-.73	2.28
2004	.53	2.1
2005	.49	1.87

No. 1
HB 164
3/4/87

Production Impact of Extend5 (Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1987	0	0	0	0	-.01	0	0	0	-.01
1988	-.	-.12	-.94	-.02	-.02	0	0	0	-.97
1989	-.69	-.12	-.07	-.04	-.03	0	0	0	-.95
1990	-.6	-.12	-.11	0	-.03	0	0	0	-.86
1991	-.57	-.11	-.15	-.03	-.05	0	0	0	-.91
1992	-.52	-.1	-.15	-.06	-.05	0	0	0	-.88
1993	-.49	-.09	-.14	-.06	-.06	0	0	0	-.84
1994	-.44	-.11	-.14	-.04	-.07	0	0	0	-.8
1995	-.39	-.07	-.09	-.05	-.05	0	0	0	-.65
1996	-.35	-.08	-.12	-.05	-.05	0	0	0	-.63
1997	-.32	-.08	.01	-.04	-.06	0	0	0	-.49
1998	-.43	-.05	.03	-.03	-.09	0	0	0	-.57
1999	-.25	-.04	.02	-.01	-.02	0	-.02	0	-.32
2000	-.22	-.03	-.02	-.01	-.03	0	-.02	0	-.33
2001	-.2	-.03	.02	0	-.02	0	-.02	0	-.25
2002	-.18	-.02	.01	0	-.02	0	-.02	0	-.23
2003	-.16	-.01	-.01	0	-.01	0	-.01	0	-.2
2004	-.19	0	.04	0	-.01	0	-.01	0	-.17
2005	-.13	.01	.04	0	0	0	-.01	0	-.09
									0
									0
Total	-6.9	-1.15	-.87	-.44	-.68	0	-.11	0	-10.15

M E M O R A N D U M

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

4-164

February 27, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist

Subject: More ELF

Per your request, I have examined the revenue and production impact of extending the 10 year period during which the ELF is subject to the .7 or greater test to 15 years and fixing the value of the Production at the Economic Limit (PEL) at 300 barrels per well per day. Prudhoe Bay and Lisburne are the fields currently producing with a calculated ELF greater than .7 and thus would be directly impacted by this change in the State severance tax law. On average, the calculated ELF for Prudhoe is not expected to fall below 0.7 over the next 5 years. We expect the Lisburne ELF to fall below 0.7 in FY 1989 and subsequent years.

By setting the PEL at 300, the ELF no longer would be sensitive to the price of oil or the cost of producing oil and would be totally dependent on per barrel productivity for a producing lease or property. Over the next 5 years as Prudhoe Bay production begins to decline the only reason for an ELF less than 0.7 would be if a significantly greater than expected number of additional wells were drilled. For example we currently expect Prudhoe to produce on average, 0.984 million barrels per day in 1992 from 465 wells providing an ELF of.7911. If this same amount of oil were produced from 705 wells, the ELF would be equal to .6906.

The following tables illustrate the revenue impact and production impact of extending the ELF time line to 15 years and fixing the value of PEL at 300. These results are generated by the DOR revenue simulation model using the December 1986 input assumptions. The most significant result other than the revenues generated is that there is almost no average expected effect on North Slope production.

Standard Alaska
Production Company
900 East Benson Boulevard
P O Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

May 18, 1987

STANDARD
ALASKA PRODUCTION

Senator Jan Faiks
Alaska State Legislature
P.O. Box V
Juneau, Alaska 99811

Dear Senator Faiks:

In his letter of May 17 to the members of the Senate, the Commissioner of Revenue maintains that only by increasing the severance tax on Alaska's oil industry can Alaskans receive their fair share of economic benefits from Alaska's petroleum activity. The Commissioner cites as evidence the analysis of North Slope development expenditures prepared by our industry as proof of his claim.

We strongly believe the Commissioner has misrepresented this analysis and is wrong in calling for passage of HB 164 which increases severance taxes on the industry for the following reasons:

1. The numbers in the analysis do not include the billions of dollars paid to the state of Alaska as income taxes, property taxes, severance taxes, royalties or oil and gas conservation taxes during this period;

2. The figures represent dollars spent on capital terms only. For instance, the numbers do not include installation costs of North Slope facilities which total in the billions of dollars awarded to Alaskan contractors;

3. The Commissioner's letter ignors the fact that Alaska does not have the ability to manufacture many of the facilities (such as oil pipelines and production modules) which are necessary for oil production in Alaska;

4. The Commissioner neglects the millions of dollars spent by the industry each year in payroll and salaries for their employees and those of their contractors which provide services such as security, drilling rigs, catering and routine machine maintenance; and

5. We challenge the Commissioner's assertion that additional severance taxes will provide direct economic benefits to Alaskans. The additional funds will undoubtedly go to

continue to fund unnecessary high levels of government which recent polls indicate Alaskan citizens want to cut back.

We at Standard strongly urge you to oppose HB 164 and any other tax measure that would adversely affect the oil industry.

Sincerely,

R. A. Straub
Vice President
External Affairs

P.S. In the interests of clarity, I have attached for your information a paper prepared which is in response to an earlier paper prepared by the Office of Management and Budget.

cc: Commissioner Malone
Department of Revenue

Greg Erickson
Office of Management and Budget

The "ELF"
and
North Slope Oil Production

Information of Importance on CSHB-164

Major points Alaska policymakers should know:

- If CSHB-164 were enacted, Alaska would continue to have the highest effective severance tax rate in the nation.
- A Department of Revenue projection of "lost oil production" underestimates the likely impact of CSHB-164.
- CSHB-164 is a change in the structure of the ELF formula that goes far beyond its revenue effect on Prudhoe Bay. It should be looked at with caution.
- Investment funds for Endicott and Lisburne, new fields on the North Slope, have been largely generated by Prudhoe Bay. A tax "break" on marginal fields, cited by advocates for CSHB-164, would be offset by a larger tax bite on Prudhoe, which produces the investment funds for "marginal fields".

Standard Alaska Production Company, May 12, 1987

On April 21, 1987 the Office of Management and Budget issued a collection of material on the ELF, the Economic Limit Factor in Alaska's oil and gas severance tax. Many points made by OMB are misleading. Space limits limit our response to just a few.

OMB implies that if CSHB-164 were enacted, Alaska would still be within the range of severance taxes in other states. In fact, Alaska would continue to have the highest effective severance tax rate.

OMB uses only the Kuparuk field as an example, which accounts for only one seventh of Alaska's oil output, and cites an effective tax rate of 10.7%. However, *under CSHB-164 the average tax on all Alaska production would be 13.4%.* What accounts for the difference, of course, is the higher tax (almost 15%) that would apply to Prudhoe Bay, which provides most of Alaska's oil production.

CSHB 164 ANALYSIS: Including all Alaska oil production (FY 88)

STATE	CSHB 164 TAX AS PERCENT OF VALUE
Alaska (proposed)	13.4%
Louisiana	12.5%
Alaska (existing)	11.6%
Oklahoma	7.0%
Texas	4.9%
California	0%

OMB ANALYSIS: Looking only at Kuparuk (FY 88)

STATE	KUPARUK TAX AS A PERCENT OF VALUE
Louisiana	12.5%
Alaska (proposed)	10.7%
New Mexico	8.0%
Alaska (existing)	7.6%
Oklahoma	7.0%
Wyoming	6.0%
Texas	4.9%

The average severance tax rate of the four other top oil producing states is 6.1%. *The effective severance tax rate for Alaskan production under current law is almost twice the average of the other top oil producing states.* The new ELF would increase the effective rate another 1.8%, putting Alaska far above any other state.

But still, isn't OMB's point that CSHB-164 would keep taxes low on smaller fields other than Prudhoe, and actually decrease taxes on some small "marginal fields"?

What is obscured is that there are "marginal projects" within the Prudhoe Bay field itself, development programs that could apply more intensive development drilling or enhanced oil recovery to the reservoir. *These projects could recover huge amounts of oil - the equivalent of several fields like Endicott or Lisburne, two new "marginal fields" now under development.* In all likelihood, outside of ANWR *the biggest prospect for major new recoverable oil reserves is right in the Prudhoe Bay field itself.*

But still, isn't there a tax decrease on Endicott and Lisburne?

We believe OMB's figures overstate it. Our estimates of its effect are different, and that it does not amount to a significant savings. *It should also be pointed out that the 33% tax increase on Kuparuk (by OMB's figures) will have a serious adverse effect on further development in that field.* It is worth noting that the vast bulk of the investment funds for Lisburne and Endicott are coming from the Prudhoe Bay field, since Prudhoe owners are also involved in development of these smaller fields. The same is true for Kuparuk. Higher taxes on Prudhoe drains off capital that could be invested in new projects.

What about Milne Point? OMB cites that case. Doesn't it illustrate the "quirks" in the current ELF?

If there are problems in how the ELF applies to particularly marginal fields, the current statute provides a mechanism to solve them - the right to challenge the "economic limit" in the formula itself. A reasonable interpretation of the statute would protect truly marginal fields. CSHB-164 actually provides relief for small fields - marginal or not - and imposes a greater burden on larger fields, even those marginally economic. DOR could, by regulation, solve the "problems" cited by advocates for CSHB-164. They do not justify a change in the statute.

In recent House testimony, Standard said that with lower oil prices the state's overall "share" of oil production revenues have increased sharply. OMB says this is "false". Is it?

No. And OMB cites no data in making that claim. In fact, Standard's analysis is based on Department of Revenue data.

Standard testified that at $15 oil prices ($9 wellhead), the *state share* of net production income based on a Department of Revenue study, *would be 96% for FY 1988-1992.* The DOR study referenced is: "Sensitivity Analysis of Projected Revenue Collections", by John Larson et al. (December 1986). The purpose of the study was to provide the economic effect of Alaska's oil taxes at various wellhead prices. Following is page 93 of the study which addresses $15 oil prices ($9 wellhead). Page 93 is captioned, "Percentage Share Comparison - Calculation of State Petroleum Production Revenue as a Percentage of Petroleum Production Net Income."

TABLE II-9-8
PERCENTAGE SHARE COMPARISON
CALCULATION OF STATE PETROLEUM PRODUCTION REVENUES
AS A PERCENTAGE OF
PETROLEUM PRODUCTION NET INCOME
(1-1988A1) SENSITIVITY ANALYSIS 89/0 WHV

FISCAL YEAR	TOTAL PETRO PRODN GROSS INCOME MM$/Y	TOTAL PETRO PRODN NON TAX DEDUCTS MM$/Y	TOTAL PETRO PRODN NET INCOME MM$/Y	CURRENT LAW STATE PETRO PRODN REVENUE MM$/Y	REVENUE VS NET INCOME %	MOSS STATE PETRO PRODN REVENUE MM$/Y	REVENUE VS NET INCOME %
1986	6142.82	3384.18	2778.63	1867.26	67.20	1817.31	65.40
1987	5209.70	3471.83	2537.87	1845.76	72.65	1729.39	68.14
1988	5983.52	3856.79	2126.73	1688.29	79.38	1524.93	71.70
1989	5915.67	4101.18	1814.49	1663.12	91.66	1483.11	81.74
1990	5660.66	4021.98	1638.68	1583.60	96.67	1397.89	85.34
1991	5279.85	3859.62	1420.83	1468.74	103.37	1281.38	90.21
1992	4864.68	3780.83	1083.77	1356.61	124.99	1184.64	109.28
1993	4548.23	3803.49	744.74	1298.73	167.07	1126.53	147.31
1994	4318.88	3643.78	697.10	1202.65	172.49	1071.87	153.76
1995	4156.91	3343.68	813.23	1132.98	139.21	1030.62	126.73
1996	3720.82	3437.23	732.79	1014.65	138.46	934.24	127.49
1997	3442.69	2784.54	658.16	917.09	139.45	852.61	129.55
1998	3125.52	2454.54	648.98	829.96	124.66	778.04	116.30
1999	2960.87	2124.96	575.96	762.66	132.32	719.39	124.92
2000	2685.26	2182.13	503.13	698.61	138.73	662.77	131.73
2001	2674.83	2062.85	611.99	637.65	104.17	607.58	147.68
2002	2328.39	1959.97	368.42	569.07	154.49	565.37	153.46
2003	1920.78	1535.17	385.61	497.23	128.95	481.50	124.87
2004	1798.92	1490.76	308.16	458.12	148.67	447.62	145.26
2005	1696.31	1450.30	246.02	425.81	173.08	418.28	170.02
	27,704	19,420	8,084	7,758			

It is clear (and no one has contended otherwise) that the data is from the December DOR study. What is also difficult to dispute is:

- $7,758MM (current law state petroleum production revenue) divided by $8,084MM (total petroleum production net income) times 100 (to convert to a %) is 96%, and

- the schedule on page 93 is intended specifically to address the state share issue.

In conversations with Standard, Department of Revenue analysts agreed the information was not being misinterpreted.

The point Standard was making in its testimony is that low oil prices have dramatically reduced producers' net return on production revenues, and that state royalties and taxes, because they are levied on gross field revenues rather than net, become much larger as a percentage of the overall. *By increasing taxes, CSHB-164 would essentially reduce industry's share of net production income (as defined by Department of Revenue) to zero.* This is hardly an incentive for further development activity.

But don't pipeline profits offset that?

Although believing that transportation income is irrelevant in determining tax policy for production taxes, Standard testified that *inclusion of the transportation income still resulted in a state share of 59%* over the same period and at the same price.

OMB has numbers which indicate industry's "share" at much different levels. How is that?

OMB looks at 1982 through 1985, years with high oil prices, in their claim of a high industry "share". They also include pipeline income in the calculation. Our analysis looks five years into the future, using lower prices and assuming that low to moderate prices will continue for some time into the future. Governor Cowper, and many oil companies, have said that it is reasonable to assume $15 oil prices as a long-term "planning" figure, although prices have shown some recent short-term improvement. Additionally, we think there are also serious errors in the assumptions used in the OBM "share of the pie" analysis, particularly assumptions of federal tax liability.

The OMB report relying on a Department of Revenue analysis states that the cumulative loss of production from the new ELF is 21 million barrels. Do you agree?

No. Any sense of security associated with a loss of 21 million barrels is a false sense of security. Arco has estimated the "production lost" at a much higher figure - 200 million barrels just in Prudhoe Bay.

The likelihood that the 21 million barrel "lost production" is substantially understated is apparent from looking only at proposed additional development at Prudhoe over the next few years. We see the potential of the Prudhoe Bay reservoir, with current technology, at about ten billion barrels recoverable. Five billion barrels have been produced already. With facilities and wells now in place, four billion - for a total of nine - can be produced. *Recovering the additional one billion barrels will require additional capital investment in facilities and drilling. Many of these future investment decisions are only marginally economic. This future development and some of the expected production from the current wells and facilities is jeopardized by proposed changes in the ELF.*

CSHB-164 is no mere "technical correction" of state oil tax laws, or even just halting a scheduled reduction of the 15% severance tax on Prudhoe Bay. It is a restructuring of the ELF formula that eliminates its effectiveness as an incentive for further development drilling. Because of this, it should be looked at very cautiously.

How is Alaska's tax structure viewed by others?

In a two-year study of state economic policies published in March, 1987, "Making the Grade: The Development Report Card for the States" by the Washington-D.C.-based Corporation for Enterprise Development, *Alaska was rated 49th (tied with Tennessee) in the state policies toward economic development index.* A prime component in this index is an effective and equitable tax code. Alaska's low rating in the index is tied to Alaska's heavy dependence on oil revenues.

MEMORANDUM

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

February 11, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist

Subject: New ELF

Per your request, I have examined the revenue and production impacts associated with changing the ELF to consider field size. This modification is similiar to the one outlined in HB 545 and presented in analysis done by myself in papers prepared for presentation to the tax committee.

Briefly, the modification is accomplished by introducing a scaling factor and also the rate of field production into the exponent of the current ELF formula. The value of this scaling factor determines at what level of production the resulting ELF is greater than under the current law. For instance, in HB 545 the factor has a value of 37,000,000 which, given a PEL of 300, translates into a break point of roughly 80,000 bbls/day. The analysis I did for the tax committee last December under the OMB modified alternative ELF used a factor with a value of 45,500,000. This translates into a break point of roughly 100,000 bbls./day. In the analysis contained in this memo I have used a factor value of 55,000,000, which results in a break point of roughly 120,000 bbls./day. A breakpoint of 120,000 bbls./day would increase the effective severance tax rate on Prudhoe Bay and Kuparuk production. It would reduce the effective severance tax rate on all other oil fields now producing or likely to produce in the next two years, including all Cook Inlet fields, Milne Point, Lisburne, and Endicott. This is because none of these fields are projected to produce at or above the 120,000 bbl./day level. I have attached a computer printout which illustrates the sensitivity of the change in effective tax rate on each field of different assumptions for production and well count using the 55 million scaling factor

Attachment 3

3-18-87

To illustrate the effect of different scaling factors on the ELF calculation I have developed the following tables. The first table illustrates the break point for various values of the scaling factor i.e. the total field production which would result in a lower ELF than that currently calculated.

Factor	Breakpoint
20000000	43479 bbls./day
30000000	65219
40000000	86958
50000000	108698
60000000	130438
70000000	152177
80000000	173917
90000000	195656
100000000	217396
110000000	239136

The following table shows the calculated ELF by North Slope field for various values of the scaling factor.

			Factor/ELF							
Field	Prod.	Prod/Well	30MM	40MM	50MM	60MM	70MM	80MM	90MM	100MM
Prudhoe	1510000	2900	.9928	.9904	.9880	.9856	.9833	.9809	.9785	.9762
Kuparuk	230000	885	.8353	.7866	.7408	.6977	.6571	.6188	.5828	.5488
Milne	20000	900	.1317	.0670	.0341	.0173	.0088	.0045	.0023	.0012
Endicott	70000	900	.5603	.4619	.3808	.3140	.2588	.2134	.1759	.1450
Lisburne	35000	1400	.5021	.3990	.3171	.2521	.2003	.1592	.1266	.1006
West Sak	100000	550	.4545	.3495	.2687	.2066	.1589	.1221	.0939	.0722

The following two tables illustrate the revenue and production impact of modifying the ELF to include field size in the formulas using the 55 millon scaling factor. The results were generated by the PETREV monte carlo simulation model that DOR uses to forecast petroleum production revenues. Interestingly the revenue impacts are not that much different from those contained in the fiscal note prepared last year concerning HB 545. The average expected production impacts are also relatively low. The mildly negative impact on Lisburne production is a result of a slightly higher TAPS tariff, due to slightly lower throughput, more than offsetting the lower severance tax burden. The negative impact on West Sak reflects the probability that should this project become economic, production may exceed 120,000 bbls/day from a large number of low productive wells.

Revenue Impact of Field Size ELF, Field Factor = 55 Million
(Millions $)

Fiscal Year	Delta 30%	Delta Mean
1987	10.45	10.93
1988	88.18	112.29
1989	98.14	136.23
1990	109.61	147.04
1991	96.13	132.35
1992	94.18	127.23
1993	91.30	124.34
1994	81.51	118.59
1995	77.60	112.06
1996	69.74	98.74
1997	62.21	92.73
1998	49.52	82.14
1999	43.91	75.70
2000	33.42	72.90
2001	31.73	72.49
2002	27.43	73.42
2003	28.46	73.09
2004	23.53	62.25
2005	20.23	47.44

Production Impact of Expo55 (Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1987	0	0	.05	0	-.03	0	0	0	.02
1988	-1.97	-.32	.23	.65	-.05	0	0	0	-1.46
1989	-1.77	-.33	.37	2.16	-.06	0	0	0	.37
1990	-1.59	-.33	.39	2.13	-.07	0	0	0	.53
1991	-1.46	-.29	.39	2.1	-.1	0	0	0	.64
1992	-1.41	-.26	.36	2.01	-.1	0	.28	0	.88
1993	-1.25	-.23	.38	1.94	-.12	0	.51	0	1.23
1994	-2.59	-.38	.32	1.41	-.47	0	.53	0	-1.18
1995	-2.24	-.37	.29	1.69	-.41	-.63	.56	0	-1.11
1996	-2.16	-.3	.18	1.22	-.37	-.77	.48	0	-1.72
1997	-3.12	-.27	.19	.77	-.31	-1.13	.41	0	-3.46
1998	-2.57	-.16	.18	.41	-.28	-1.13	.38	.13	-3.04
1999	-2.18	-.1	.16	.06	-.21	-1.23	.58	.17	-2.75
2000	-1.93	-.07	.03	-.18	-.17	-1.23	.51	.18	-2.86
2001	-1.77	-.02	-.03	-.3	-.11	-1.26	.43	.21	-2.85
2002	-1.46	-.01	-.09	-.36	-.07	-1.32	.34	.23	-2.74
2003	-1.31	0	-.06	-.33	-.02	-1.12	.24	.23	-2.37
2004	-1.27	-.01	.01	-.34	-.02	-1.11	.22	.23	-2.29
2005	-1.13	-.04	-.03	-.26	-.04	-1.08	.18	.28	-2.12
Total	-33.18	-3.49	3.32	14.78	-3.01	-12.01	5.65	1.66	-26.28

THE EFFECT OF THE FIELD SIZE ELF ON THE PRUDHOE BAY SEVERANCE TAX RATE

	Producing Wells	Production (Bbl/day)	Current Elf	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1989	Increased Effective Tax Rate FY 1988
December DOR 1988 Mean	520	1510000	.8460	.9833	.1269	.1475	.0206
		Sensitivity Table					
	500	1450000	.8458	.9863	.1269	.1479	.0211
		1500000	.8500	.9872	.1276	.1481	.0205
		1525000	.8532	.9876	.1280	.1481	.0202
		1550000	.8555	.9880	.1283	.1482	.0199
		1575000	.8577	.9884	.1287	.1483	.0196
	520	1450000	.8399	.9857	.1260	.1479	.0219
		1500000	.8450	.9867	.1268	.1480	.0212
		1525000	.8475	.9871	.1271	.1481	.0209
		1550000	.8499	.9875	.1275	.1481	.0206
		1575000	.8522	.9879	.1278	.1482	.0204
	540	1450000	.8339	.9851	.1251	.1478	.0227
		1500000	.8393	.9861	.1259	.1479	.0220
		1525000	.8418	.9866	.1263	.1480	.0217
		1550000	.8443	.9870	.1266	.1481	.0214
		1575000	.8467	.9874	.1270	.1481	.0211
	550	200000	.0691	.2024	.0104	.0304	.0200
		225000	.1310	.3406	.0190	.0511	.0313
		250000	.1913	.4533	.0287	.0680	.0393
		275000	.2454	.5429	.0368	.0814	.0446
		300000	.2939	.6139	.0441	.0921	.0480

THE EFFECT OF THE FIELD SIZE ELF ON THE KUPARUK SEVERANCE TAX RATE

	Producing Wells	Production (Bbl/day)	Current ELF	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1988	Increased Effective Tax Rate FY 1988
December DOR 1988 Mean	260	250000	.5299	.6569	.0795	.0985	.0191
		Sensitivity Table					
	250	200000	.4864	.6500	.0730	.0975	.0245
		225000	.5370	.7187	.0806	.1078	.0272
		250000	.5787	.7698	.0868	.1155	.0287
		275000	.6137	.8087	.0921	.1213	.0293
		300000	.6433	.8382	.0965	.1258	.0293
	260	200000	.4686	.6357	.0703	.0953	.0251
		225000	.5206	.7069	.0781	.1060	.0279
		250000	.5636	.7601	.0845	.1140	.0295
		275000	.5996	.8006	.0899	.1201	.0301
		300000	.6302	.8319	.0945	.1248	.0303
	270	200000	.4511	.6213	.0677	.0932	.0255
		225000	.5014	.6951	.0757	.1043	.0286
		250000	.5486	.7504	.0823	.1126	.0303
		275000	.5857	.7925	.0879	.1189	.0310
		300000	.6172	.8250	.0926	.1238	.0312
	280	200000	.4358	.6069	.0651	.0910	.0260
		225000	.4884	.6833	.0733	.1025	.0292
		250000	.5337	.7406	.0801	.1111	.0310
		275000	.5719	.7843	.0858	.1176	.0319
		300000	.6043	.8181	.0906	.1227	.0321

THE EFFECT OF THE FIELD SIZE ELF ON THE MILNE SEVERANCE TAX RATE

2-18-87

	Producing Wells	Production (Bbl/day)	Current ELF	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1988	Decreased Effective Tax Rate FY 1988
December DOR 1988 Mean	22	20000	.5411	.0024	.0663	.0011	-.0651
Sensitivity Table							
	15	10000	.3998	0	.0490	0	-.0490
		15000	.5707	.0128	.0709	.0016	-.0693
		20000	.6765	.0967	.0829	.0118	-.0710
		25000	.7376	.2333	.0904	.0286	-.0618
		30000	.7794	.3704	.0955	.0454	-.0501
	20	10000	.2454	0	.0301	0	-.0301
		15000	.4569	.0019	.0560	.0002	-.0557
		20000	.5707	.0380	.0709	.0047	-.0662
		25000	.6565	.1336	.0804	.0164	-.0641
		30000	.7102	.2557	.0870	.0313	-.0557
	10	10000	0	0	0	0	0
		15000	.0848	0	.0104	0	-.0104
		20000	.2454	.0002	.0301	0	-.0300
		25000	.3662	.0003	.0449	.0010	-.0439
		30000	.4569	.0041	.0560	.0054	-.0506
	40	10000	0	0	0	0	0
		15000	0	0	0	0	0
		20000	.0295	0	.0036	0	-.0036
		25000	.1420	.0001	.0174	0	-.0174
		30000	.2454	.0037	.0301	.0005	-.0296

THE EFFECT OF THE FIELD SIZE ELF ON THE ENDICOTT SEVERANCE TAX RATE

3-18-87

	Producing Wells	Production (Bbl/day)	Current ELF	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1988	Decreased Effective Tax Rate FY 1988
December 1988 Mean	69	62500	.5397	.2227	.0461	.0273	-.0188
Sensitivity Table							
	50	40000	.4864	.1160	.0596	.0142	-.0454
		60000	.6433	.4152	.0788	.0509	-.0279
		80000	.7275	.6214	.0891	.0761	-.0130
		100000	.7794	.7423	.0955	.0909	-.0045
		120000	.8149	.8155	.0998	.0999	.0001
	75	40000	.2815	.0226	.0345	.0028	-.0317
		60000	.4864	.2378	.0596	.0291	-.0305
		80000	.6027	.4692	.0738	.0575	-.0164
		100000	.6765	.6267	.0829	.0768	-.0061
		120000	.7273	.7282	.0891	.0892	.0001
	90	40000	.1785	.0058	.0219	.0007	-.0212
		60000	.3998	.1609	.0490	.0197	-.0293
		80000	.5419	.3072	.0664	.0377	-.0287
		100000	.6172	.5616	.0756	.0688	-.0068
		120000	.6765	.6775	.0829	.0830	.0001
	110	40000	.0691	.0003	.0085	0	-.0084
		60000	.2939	.0872	.0360	.0107	-.0253
		80000	.4424	.2956	.0542	.0362	-.0180
		100000	.5411	.4799	.0663	.0588	-.0075
		120000	.6107	.6118	.0748	.0749	.0001

THE EFFECT OF THE FIELD SIZE ELF ON THE LISBURNE SEVERANCE TAX RATE

	Producing Wells	Production (Bbl/day)	Current Elf	New ELF Field Size Factor = 55000000	Current Effective Tax Rate FY 1988	New Effective Tax Rate FY 1988	Decreased Effective Tax Rate FY 1988
December DOR 1988 Mean	20	35000	.7475	.2855	.1124	.0420	-.0696
		Sensitivity Table					
	20	25000	.6565	.1336	.0985	.0200	-.0784
		35000	.7475	.3734	.1124	.0560	-.0564
		50000	.8220	.6250	.1233	.0939	-.0294
		75000	.8800	.8156	.1320	.1223	-.0097
		100000	.9095	.8920	.1364	.1339	-.0025
	35	25000	.4338	.0184	.0651	.0028	-.0623
		35000	.5787	.1544	.0868	.0232	-.0637
		50000	.6967	.4213	.1045	.0632	-.0413
		75000	.7935	.6916	.1190	.1037	-.0153
		100000	.8436	.8160	.1265	.1224	-.0041
	50	25000	.2454	.0012	.0368	.0002	-.0366
		35000	.4240	.0533	.0636	.0080	-.0556
		50000	.5787	.2704	.0868	.0406	-.0462
		75000	.7102	.5796	.1065	.0869	-.0196
		100000	.7794	.7423	.1169	.1114	-.0056
	80	25000	.0072	0	.0011	0	-.0011
		35000	.1695	.0023	.0254	.0003	-.0251
		50000	.3669	.0909	.0550	.0136	-.0414
		75000	.5536	.3896	.0830	.0584	-.0246
		100000	.6565	.6046	.0985	.0907	-.0078

MEMORANDUM State of Alaska

TO: Mary A. Nordale
Commissioner of Revenue

DATE: October 31, 1985

FILE NO:

TELEPHONE NO:

FROM: Vincent D. Wright VW
Chief, Research Section

SUBJECT: HB 353

The HB 353 versus current law analysis is virtually complete with the exception of the TAPS settlement impact. The incorporation of the TAPS settlement and its impact on HB 353 versus current law we hope to complete by the end of November.

I naturally have greater confidence in the results of this project as compared to our preliminary work in that we took the time to conduct a thorough analysis of all the revenue and expenditure items necessary to put together this report. The various items, particularly on the expenditure side, are very complex in their construction and require a great deal of time and effort in order to obtain accuracy and objectivity. I insisted on this approach, however, in the belief that our decision-makers would prefer being able to make informed, and therefore, responsible decisions.

The basis of this report is also much broader in scope than our original analysis in that we addressed additional questions such as the effect of differing tax structures on the "marginal fields", various definitions of the "pie", alternative price scenarios, and a much longer time period.

The scope of study, assumptions, and conclusions are attached but I would like to reiterate in this letter our basic conclusions in synopsis form.

1. If, for the years FY 1982 through FY 1985, the old separate accounting and severance tax laws had been in effect, the State would have received more revenue disregarding, of course, what might happen in future court actions.

2. Our projections indicate that under a proposal such as HB 353 and for the period projected (FY 1985 - FY 2005), the amount of cumulative revenue would be greater than under current tax law.

3. During the first few years, more revenue is generated under HB 353 than under current law. Our projections also indicate, however, that in later years a crossover point exists with the result that more revenue is generated under the current tax structure than under the HB 353 proposal. The causes for this are discussed in detail in the report.

4. Under both tax structures, revenues will decline on a year-to-year basis.

5. A proposal such as HB 353 is more oil price sensitive than the current tax structure. This means that if oil prices move up, the State would gain more revenue under an HB 353 type proposal than under existing law. It also means that if oil prices move down, the State will lose more revenue under an HB 353 type proposal than under existing tax law.

6. The State's share of the "pie" is defined via two approaches, both described in detail later in this report. In the period FY 1982 through FY 1985, there is no evidence to support a trend indicating that the State received more or less of the total "pie".

7. Based on the period FY 1985 through FY 2005 and under all scenarios, the State generally receives an increasing share of the "pie".

8. The proposed change from existing law to HB 353 does not, given our assumptions, materially effect the feasibility of developing the "marginal fields". However, there are other factors which must be considered that are explained in the body of this report.

9. The change in the price of oil does have a significant impact, relatively speaking, on whether or not a corporation would pursue the development of a "marginal field".

ANALYSIS OF HB 353

The following materials contain our analysis of the projected revenue impact of HB 353 based on the June, 1985, Petroleum Revenue Forecast assumptions. The analysis was performed for the time period fiscal year (FY) 1985 through FY 2005 and for three alternative oil price and production scenarios; moderate, low and high, corresponding approximately with the Mean, 30 percent and 70 percent forecast assumptions. The analysis shows the projected change in Petroleum Corporate Income Tax and Petroleum Severance Tax collections for the time period under the three scenarios, as a result of enacting HB 353 given the provisions and effective dates contained in that bill.

The materials also contain our analysis of the estimated revenue impact of SB 524 (current law) for the time period FY 1982 through FY 1985, given the oil and price and production which actually occurred during that time period. Again, the analysis shows the estimated change in Petroleum Corporate Income Tax and Petroleum Severance Tax collections for the time period as a result of the enactment of SB 524.

The materials are presented in the following order:

I. A description of the changes made and proposed changes to the Petroleum Corporate Income Tax and the Petroleum Severance Tax as a result of the enactment of SB 524 and the proposed enactment of HB 353.

II. A description of the methodology and assumptions used to estimate the revenue collections under the pre-SB 524 separate accounting Petroleum Corporate Income Tax for fiscal years 1982 through 1985 and to project what the revenue collections under the HB 353 separate accounting Petroleum Corporate Income Tax would be for fiscal years 1985 through 2005.

III. A description of the methodology and assumptions used to project what revenue collections will be under the current modified apportionment Petroleum Corporate Income Tax for fiscal years 1985 through 2005.

IV. Summary tables and descriptions showing the numerical results of the analysis.

V. Conclusions of our analysis and comparison with earlier analysis.

I.

Prior to enactment of SB 524, the Petroleum Corporate Income Tax was determined on a separate accounting basis and taxed at a maximum marginal rate of 9.4 percent. This separate accounting corporate tax structure was in effect for calendar years 1978 through 1981.

Under separate accounting, a corporation's gross petroleum production and gross petroleum pipeline transportation income was the starting point for calculation of taxable income. Gross petroleum production income was determined by taking the product of the corporation's field production and wellhead value. Gross petroleum pipeline transportation income was determined by taking the product of the corporation's pipeline thruput and tariff. Deductions from gross petroleum production or gross petroleum pipeline transportation income specifically associated with those activities in the State were allowed in calculating the corporation's net income subject to the tax rate.

The Oil Severance Tax, which was in effect prior to the enactment of SB 524, and which was an allowable deduction from gross petroleum production income under the separate accounting corporate tax, had a rate of 12.25 percent modified by an economic limit factor (ELF) for production from all fields. The effective tax rate, the product of 12.25 percent and the ELF, was levied against the product of net (after royalty share) production and gross wellhead value to determine the tax liability.

With enactment of SB 524, the current tax structure with respect to the Petroleum Corporate Income Tax and the Petroleum Severance Tax was put into effect. The determination of taxable income under the Petroleum Corporation Tax was changed from the separate accounting basis described above to a modified apportionment basis which is currently in effect.

Under the provisions of SB 524, modified apportionment was put into effect starting in calendar year (CY) 1982 with a maximum marginal tax rate of 9.4 percent. In addition, the maximum marginal tax rate for the last year that separate accounting was in effect, CY 1981, was increased to 11 percent. Under modified apportionment, a corporation's adjusted worldwide petroleum business federal taxable income is allocated to Alaska based on an apportionment factor to determine its Alaska net petroleum business income subject to the tax rate. If the corporation is engaged in both petroleum production and petroleum pipeline transportation in Alaska, the apportionment factor is calculated as the average of three factors. The factors are: (1) extraction, the corporation's Alaska net petroleum production divided by its total worldwide net petroleum production; (2) property, the corporation's Alaska average petroleum business property divided by its total worldwide average petroleum business property; and (3) sales, the corporation's Alaska petroleum business sales and tariffs divided by its total worldwide petroleum business sales and tariffs.

The Oil Severance Tax rate under the provisions of SB 524 was changed from 12.25 percent to 15 percent for production from the Sadlerochit and Cook Inlet fields. The ELF was set to equal 1.00 as long as the calculated ELF was .7 or greater or for the first 10 years of production. The tax rate for production from Kuparuk and other North

Slope fields remained at 12.25 percent for the first 5 years of production from the field and then went to 15 percent. The ELF provisions for these fields were the same as for Sadlerochit and Cook Inlet. This represents the current Oil Severance Tax structure and has been in effect since the beginning of FY 1982.

HB 353 proposes to once again change the tax structure with respect to the Petroleum Corporate Income Tax and the Petroleum Severance Tax. Under the provisions of HB 353, the Petroleum Corporation Income Tax would again be determined on a separate accounting basis, very similar to the method used prior to passage of SB 524. For corporations engaged in petroleum production or petroleum pipeline transportation, gross petroleum production and transportation income would be determined in the same manner as pre-SB 524. Deductions allowed in determining net taxable income would also be similar but with a few exceptions. Under HB 353, the Federal Crude Oil Windfall Profits Tax would not be an allowable deduction where it was under the pre-SB 524 separate accounting corporate income tax. Also, although Oil Severance Taxes are allowed as a deduction under both laws, HB 353 proposes to change the Oil Severance Tax law provisions. Thus, the severance tax would be different under each law. Under HB 353, corporations engaged in petroleum exploration activities in Alaska but with no petroleum production or pipeline transportation activities would also be subject to the separate

accounting tax. This was not the case under the pre-SB 524 law. The maximum marginal tax rate would remain at 9.4 percent. HB 353 would enact this new separate accounting Petroleum Corporate Income Tax beginning with CY 1985.

HB 353 would change the Oil Severance Tax rate back to 12.25 percent for all fields beginning in CY 1987. The ELF provisions would remain the same as in the current law.

II.

The analysis of Petroleum Corporate Income Tax collections under separate accounting was performed on a disaggregated basis by producing field and pipeline. Estimates and projections of gross production income and allowable production deductions were developed for all fields which have produced in Alaska since FY 1982 or which are projected to have commercial production by FY 2005. The fields included were Cook Inlet, Sadlerochit and Kuparuk, all of which are currently producing. In addition, the "marginal" North Slope fields of Milne Point, Endicott, Lisburne, West Sak and Point Thompson were also included. The only prospective North Slope field excluded was Seal Island as it is not expected to have commercial production before FY 2005. Estimates and projections of gross pipeline transportation income and allowable deductions were also developed for TAPS for fiscal years 1982 through 2005.

Actual gross production and wellhead values by field were used to derive estimated gross production income for fiscal years 1982 through 1985. Also, actual TAPS thruput and tariffs were used to derive estimated gross transportation income for this period.

Using the Petroleum Revenue Forecasting Simulation model with its feasibility analysis capabilities, six separate production scenarios by field were generated for fiscal years 1986 through 2005. This means that for each field where three different price scenarios and two different tax structures (current law and HB 353) are considered, then six different production scenarios will result. The three different future oil price scenarios corresponded approximately with the June, 1985 Forecast, Mean, 30 percent and 70 percent price assumptions. It should be noted that for the purposes of this sensitivity analysis, three distinct future price scenarios were used in the model whereas for the normal forecasting analysis, the Mean, 30 percent and 70 percent scenarios are a result of an entire probability distribution of inputs and outputs. Therefore, the correspondence with the June, 1985 Forecast will not be exact.

In addition, production effects by field for each future oil price scenario were analyzed assuming both the current tax structure and the proposed HB 353 tax structure would be in effect for the period. The results of this analysis indicated that the aggregate production impacts of HB 353 over the time period would be insignificant when compared to

the current tax structure. Cumulative North Slope production for the period FY 1986 through FY 2005 would be only 0.43 percent lower under HB 353 than under current law given the Mean case price scenario, 0.27 percent lower given the 30 percent case price scenario and 0.10 percent lower given the 70 percent case price scenario.

The impact of alternative price scenarios, however, was found to be much more significant than alternative law scenarios. Cumulative North Slope production through FY 2005 given the current law was found to be 3.39 percent lower under the 30 percent price scenario than under the Mean and 7.32 percent higher under the 70 percent price scenario when compared to the Mean.

This feasibility analysis was based on a real after tax discounted cash flow rate of return (DCFROR) analysis applied to each current and prospective North Slope field along with assumptions about oil prices, development and operating costs, effective tax rates and desired rates of return. A detailed description of the feasibility submodel can be found in the appendix to the June, 1985 quarterly Petroleum Production Revenue Forecast.

The gross production and wellhead values under HB 353 given each future price scenario generated by this analysis were used to project future gross production income by field. The sum of production from all North Slope fields under each price scenario was used to project TAPS thruput under each scenario. The TAPS tariff was assumed to remain at

$6.00 per barrel from FY 1986 through FY 2005 and along with TAPS thruput was used to project gross pipeline transportation income. Possible effects of the TAPS tariff settlement have not been considered in this analysis but will be analyzed in the near future. All wellhead value projections in this analysis assume a $6.00 per barrel TAPS tariff. If the tariff were changed it would impact wellhead value and therefore, also production and thruput which could in turn impact the tariff itself. So, the analysis is somewhat complex and will be presented separately.

Allowable separate accounting deductions by field and TAPS were estimated for FY 1982 through FY 1985 under the pre-SB 524 Petroleum Corporate Income tax law. Allowable deductions by field and TAPS were projected based on the three price and production scenarios for FY 1985 through 2005 under HB 353.

Deductions from gross production income by field were derived as follows:

Royalties which would have been deductible under the pre-SB 524 separate accounting law for FY 1982 through FY 1985 and which would be deductible under the proposed HB 353 for FY 1985 through FY 2005 were derived on the same basis. For each field, royalties were based on the State's royalty share of the field, the production from the field and the

field wellhead value less any field gathering and cleaning costs. For the period from FY 85 through FY 2005, under HB 353, royalties were different under each price scenario as each scenario had a different wellhead value and production associated with it.

Severance taxes were calculated as a deduction under both pre-SB 524 and proposed HB 353 income tax laws. However, since both SB 524 and HB 353 also change the severance tax law, the basis for calculation had to be different. For the period from FY 1982 through FY 1985 under the pre-SB 524 severance tax law, a rate of 12.25 percent modified by a calculated ELF was applied to the net after royalty share production multiplied by the wellhead value for all fields. Under HB 353, the current severance tax structure was applied to all fields from FY 1982 through the first half of FY 1987. The current tax structure taxes the Sadlerochit and Cook Inlet fields at a rate of 15 percent modified by an ELF set equal to 1.00 as long as the calculated ELF is .7 or above or for the first 10 years the field produces. Kuparuk and all other North Slope fields are taxed at a rate of 12.25 percent for the first 5 years of production and 15 percent thereafter with ELF provisions the same as for Sadlerochit and Cook Inlet. Since HB 353 proposes to change the severance tax law beginning in CY 1987, the proposed new tax structure was applied to all fields for the period from the second half of FY 1987 through FY 2005. That structure taxes production from all fields at a

rate of 12.25 percent with ELF provisions the same as under the current law. Severance taxes will be different under each price scenario for the period through FY 2005 as production and wellhead values would differ in each scenario.

Property taxes under the Alaska Petroleum Production and Pipeline Property Tax were computed as a deduction under both the pre-SB 524 law and the HB 353 proposal. The basis for each producing field was the same under both approaches. The property tax is levied at a rate of 2 percent on the assessed value of tangible production property in the field. Assessed value for production property is based on trended original cost of tangible investments considering both depreciation and replacement cost. Property taxes for most fields did not vary between one price scenario and another as the production differences were not great enough to require significantly different development costs given the capital cost functions of the Petroleum Revenue Forecasting model. The only fields for which there were property tax differences between alternative scenarios were West Sak and Sadlerochit due to the enhanced recover phase.

Federal Crude Oil Windfall Profits Tax (WPT) was calculated as a deduction under the pre-SB 524 law for the period from FY 1982 through FY 1985. The only fields subject to this tax are Sadlerochit and Cook Inlet. The tax calculation was based on the difference between wellhead value and the adjusted base price modified by a severance tax adjustment. This net windfall per barrel was multiplied by the

production from the field and then by the WPT rate of 70 percent to calculate the tax. The WPT is not an allowable deduction under HB 353 and therefore, was not deducted in calculation of net income under the tax.

Direct operating costs for each field are allowed as a deduction under both pre-SB 524 and HB 353. Operating costs were calculated for each field based on cost functions in the Petroleum Revenue Forecasting model. These functions were specified with a fixed component and a variable component which was a function of production volume. They also contained specific cost escalation rates. Operating costs varied between scenarios for each field as production volumes varied. It should be noted that operating costs used in this analysis are significantly higher than those used in the March, 1985 analysis of HB 353. This is because the operating cost estimates used in March were "bare bones" minimum estimates and included no well workovers or field engineering.

Depreciation of development costs and amortization of lease acquisition costs calculated on a units of production basis were deducted for each field for both pre-SB 524 and HB 353. Development costs include both tangible and intangible costs and are consistent with capital cost functions in the Petroleum Revenue Forecasting Model. Development cost scenarios for the fields considered did not vary with price scenarios except in the case of West Sak and Sadlerochit in the enhanced recovery

phase. Acquisition costs include lease bonus payments, successful exploration expenses and property taxes paid before production. Reserve estimates used for calculating units of production factors were based on estimated total recoverable reserves. Unit of production factors varied between scenarios as production volumes varied.

In addition to the aforementioned production deductions developed by field for analysis of pre-SB 524 and HB 353, three other deductions are allowed under both laws and were estimated on an aggregate basis instead of by field. These deductions were made against the total gross production income of all producing fields.

Uncapitalized interest and general overhead and administration expense were projected based on historical trends actually reported under the pre-SB 524 separate accounting law through CY 1981. The projections also consider the provisions of both laws which cap the maximum allowable deduction a corporation may claim for each item. The cap is the total expense of the corporation's consolidated worldwide business in those categories multiplied by the ratio of the cost of real and tangible personal property used in production in Alaska to the cost of real and tangible personal property used in the consolidated business worldwide.

Unsuccessful exploration and abandonment expenses are also allowed as a deduction under both pre-SB 524 and HB 353 separate accounting approaches. The projections were based on historical trends actually reported under the pre-SB 524 separate accounting law and allowing for

possible impacts on exploration expenditures of alternative price scenarios. The projected exploration expense was assumed to be deducted in the year of abandonment even though it may be that the corporation with the expense would have insufficient production income against which to write off their full exploration expense and hence, would have to carry losses forward. Also, as mentioned earlier under HB 353, corporations with exploration expenses but no production income would fall under separate accounting, a provision different from the pre-SB 524 law. This could increase total exploration expenses reported. However, these corporations would be carrying losses forward until they had production income to expense against and thus, this difference would not materially impact tax collections in the time frame of this analysis.

Deductions from gross transportation for TAPS were derived as follows:

All deductions allowed from gross transportation income are the same for both pre-SB 524 and HB 353 separate accounting approaches and therefore, were projected on the same basis throughout the FY 1982 through FY 2005 time period.

Direct operating costs were projected based on an operating cost function with both a fixed component and a variable component based on thruput. Specific cost escalation factors were also considered. The function was derived based on actual FERC filings. The projections differ between price scenarios as thruput varies.

Depreciation and amortization were calculated on a straight line basis and using useful life estimates as allowed by FERC. This would be the same regardless of thruput and those would not vary between scenarios.

Uncapitalized interest was calculated based on the actual TAPS debt schedule and would not vary between scenarios.

Property taxes under the Alaska Petroleum Production and Pipeline Property Tax were computed based on the assessed value of tangible TAPS property multiplied by the rate of 2 percent. The assessed value was assumed not to vary between scenarios.

Total separate accounting gross production income for all fields and gross transportation income for TAPS less all allowable production and transportation separate accounting deductions were calculated to arrive at net separate accounting income subject to the tax rate for each year. Pre-SB 524 provisions were applied for FY 1982 through FY 1985. HB 353 provisions were applied for FY 1985 through 2005. Thus, two estimates for FY 85 were made: one under pre-SB 524; the other under HB 353. This was done in order to be able to show the impact of SB 524 from FY 1982 through FY 1985 and also, the impact of HB 353 from FY 1985 through FY 2005. Net separate accounting income on a fiscal year basis was used to derive separate accounting tax liability on a fiscal year basis which in turn, was used to derive estimated separate accounting tax collections on a fiscal year basis.

III.

Under the current (SB 524) Petroleum Corporate Income Tax, corporate income is taxed on a modified apportionment basis as described earlier. The projection of future tax collections under this tax was performed on a disaggregated basis by corporation instead of by field. This is because under apportionment, the worldwide petroleum business income of each corporation is apportioned to Alaska based on factors specific to that corporation. Thus, for example, even though two corporations may have identical production, income and costs in Alaska they may not have the same taxable income under apportionment if their worldwide operations and hence, apportionment factors are different.

The current apportionment tax has been in effect since the beginning of CY 1982. Corporations thus far have filed returns for two years, CY 1982 and CY 1983, under this tax structure. The three major taxpayers are ARCO, Exxon and Sohio-BP which account for approximately 90 percent of the total tax collected. Using the information for CY 1982 and CY 1983 as a basis, projections of worldwide apportionable petroleum business income and Alaska apportionment factors for each of these three corporations were made on a calendar year basis through 2005. Calendar year tax liability for the "Big Three" corporations was thus derived. Based on the corporate ownership percentages of current and prospective fields the Big Three were assumed to continue to account for 90 percent

of total tax liability throughout the period to 2005. Thus, projections of total apportionment tax liability on a calendar year basis were derived and used to project apportionment tax collections on a fiscal year basis through FY 2005.

For each corporation, projections of Alaska Production, Property and Sales used in calculating the apportionment factors were made based on the various field production and development costs and TAPS thruput and tariff rates associated with the three different price scenarios. Also, the specific corporation's ownership percentage of each field and TAPS was considered. Worldwide income, production, sales and property projections were also made assuming different growth rates consistent with the various price scenarios.

IV.

The following tables summarize the results of our analysis under the Mean, 30 percent and 70 percent price and production scenarios.

There are three sections, each corresponding with a specific scenario.

Each section contains seven tables. The tables are described as follows:

Table 1:

The first part of Table 1 summarizes the estimated impact of SB 524 (current law) on both the Petroleum Corporate Income Tax and the Petroleum Severance Tax for FY 1982 through FY 1985.

The comparison on the Petroleum Corporate Income Tax side of the table is between the pre-SB 524 separate accounting corporate tax and the current apportionment corporate tax. Two sets of figures are shown for FY 1982. The first is as if apportionment had been in effect for the full year. The second is the actual amount collected for FY 1982 which is a combination of apportionment and separate accounting. The reason for this is that SB 524 put the current apportionment tax in effect at the beginning of CY 1982, midway through FY 1982, and also raised the maximum marginal rate under the pre-SB 524 separate accounting tax from 9.4 percent to 11 percent for the last year it was in effect, CY 1981.

The comparison on the Petroleum Severance Tax side of the table is between the pre-SB 524 severance tax and the current (SB 524) severance tax. Again, two sets of figures are shown for FY 1982, however, they are both the same because SB 524 changed the severance tax effective at the beginning of FY 1982.

The second part of Table 1 summarizes the projected impact of HB 353 on both the Petroleum Corporate Income tax and the Petroleum Severance Tax for FY 1985 through FY 2005.

The comparison on the Petroleum Corporate Income Tax side is between the current apportionment corporate tax and the proposed HB 353 separate accounting corporate tax. The figures presented assume the HB 353 separate accounting tax will be effective at the beginning of CY 1985, midway through FY 1985.

The comparison on the Petroleum Severance Tax side is between the current severance tax and the proposed HB 353 severance tax. The figures presented assume the HB 353 severance tax will be effective at the beginning of CY 1987, midway through FY 1987.

Table 2a:

Table 2a summarizes estimated and projected state petroleum revenues from production as a percentage of net production revenues.

Gross revenue for each year is the sum of production multiplied by wellhead value for all producing fields. Costs are all allowable, non-tax, separate accounting deductions associated with production. Net revenue for each year is gross revenue less costs.

State petroleum revenues include royalties, severance taxes, property taxes on production facilities and income taxes. Royalties and property taxes included are the same for all tax structures presented. Property taxes are gross and include amounts credited to local governments. Severance taxes are included on the same basis and timing

as those shown in Table 1 as to pre-SB 524, current (SB 524) and proposed HB 353 laws. Income taxes included are on the same basis and timing as those shown in Table 1 except separate accounting corporate tax under pre-SB 524 and HB 353 exclude amounts attributable to TAPS which are included in Table 1. No such adjustment was made to apportionment income taxes included under current law as it was not possible to calculate separately amounts attributable to TAPS.

Table 2b:

Table 2b summarizes estimated and projected state petroleum revenues from production and pipeline transportation as a percentage of net production and transportation revenues.

Gross revenue for each year is the sum of production multiplied by wellhead value for all producing fields plus thruput multiplied by tariff for TAPS. Costs are all allowable, non-tax, separate accounting deductions associated with production and pipeline transportation. Net revenue for each year is gross revenue less costs.

State petroleum revenues include royalties, severance taxes, property taxes on production and TAPS facilities and income taxes. Royalties and property taxes included are the same for all tax structures presented. Property taxes are gross and include amounts credited to local governments. Severance taxes are included on the same basis and

timing as those shown in Table 1 as to pre-SB 524, current (SB 524) and proposed HB 353 laws. Income taxes are included on the same basis and timing as those shown in Table 1. Separate accounting corporate tax included under pre-SB 524 and HB 353 includes amounts attributable to TAPS.

Table 3:

Table 3 summarizes income and deductions on a separate accounting basis for all petroleum production, pipeline transportation and exploration activities in the State. The fields included in production activities are Cook Inlet, Sadlerochit and Kuparuk, all of which are currently in commercial production. In addition, the prospective "marginal" North Slope fields of Milne Point, Lisburne, Endicott, West Sak and Point Thompson are also included. TAPS is included in transportation activities.

The figures presented in all columns from FY 1982 through the first FY 1985 row are based on pre-SB 524 separate accounting law. The figures presented from the second FY 1985 row through FY 2005 are based on the proposed HB 353 separate accounting law. As discussed earlier, the severance tax law and the WPT deductibility provisions are different under these two laws. The figures shown in the severance tax column were calculated based on pre-SB 524 severance tax law through the first FY 1985 row and on HB 353 severance tax law from the second FY 1985 row on.

Figures shown in the WPT column are included in total deductions and deducted in calculating net income only under pre-SB 524 law through the first FY 1985 row. All tax liability and collection figures shown in this table are calculated assuming the relevant tax structure is in effect for the full year.

Table 4:

Table 4 summarizes income and deductions on a separate accounting basis for all producing fields. All calculations are on the same basis as in Table 3 except only the producing fields are included.

Table 5:

Table 5 summarizes income and deductions on a separate accounting basis for TAPS. As discussed earlier, treatment of petroleum pipeline transportation income and deductions is the same under both the pre-SB 524 and the proposed HB 353 separate accounting tax laws. All figures presented are calculated assuming separate accounting is in effect for a full year.

Table 6:

Table 6 summarizes the impact of the WPT deduction on separate accounting tax liability. Only Sadlerochit and Cook Inlet production is subject to the WPT. All other North Slope fields are exempt.

HB 353 AND SB 524
ANALYSIS
JUNE, 1985
MEAN CASE ASSUMPTIONS

SUMMARY TABLES

TABLE 1

Old Law (Pre SB 524)

Current Law (AS43.20 & AS 43.55)

Proposed Law (HB 353)

(all current FY $)

Fiscal Year	To. Corp Inc Tax Collections: Pre SB 524	AS 43.20	Diff	Total Prodn Tax Liability: Pre SB 524	AS 43.55	Diff	Total Gain or Loss
82	837.62	242.50	-595.12 1)	1219.03	1581.70	362.67	-232.45
			Impact SB 524			Impact SB 524	Impact SB 524
82	837.62	668.90	-168.72 2)	1219.03	1581.70	362.67	193.95
83	796.15	236.00	-560.15	1098.94	1493.70	394.76	-165.39
84	782.86	265.10	-517.76	1032.93	1393.10	360.17	-157.59
85	797.00	168.60	-628.40	1013.86	1388.50	374.64	-253.76
			Impact HB 353	existing		Impact HB 353	Impact HB 353
	HB 353			AS 43.55			
85	448.48	168.60	279.88 3)	1388.50	1388.50	0.00	279.88
86	698.21	228.07	470.15	1204.74	1204.74	0.00	470.15
				HB 353			
87	607.04	241.37	365.67	979.68	1072.99	-93.31	272.36
88	567.21	249.25	317.96	685.93	830.45	-144.52	173.44
89	550.19	252.48	297.71	661.33	794.12	-132.79	164.92
90	519.30	254.00	265.30	640.39	761.26	-120.87	144.43
91	476.02	251.48	224.55	603.23	707.14	-103.91	120.64
92	466.96	248.45	218.51	610.04	715.61	-105.57	112.94
93	466.49	244.40	222.09	609.35	719.25	-109.90	112.19
94	434.06	236.82	197.24	562.39	660.96	-98.57	98.67
95	403.64	228.19	175.44	535.46	631.20	-95.74	79.70
96	370.16	219.58	150.58	490.99	580.20	-89.21	61.37
97	343.05	211.35	131.69	456.75	539.66	-82.89	48.81
98	321.93	204.13	117.80	427.43	503.60	-76.17	41.63
99	302.91	197.49	105.42	402.26	471.98	-69.72	35.70
2000	290.31	190.00	100.31	372.55	437.26	-64.71	35.60
01	257.19	180.10	77.09	326.22	377.30	-51.08	26.01
02	212.73	169.31	43.42	279.22	322.12	-42.90	0.52
03	170.62	159.82	10.81	245.16	280.13	-34.97	-24.16
04	141.77	150.55	-8.78	221.49	247.03	-25.54	-34.32
05	109.07	140.64	-31.57	201.86	221.37	-19.51	-51.08
SUM85-05	8157.35	4426.09	3731.26	11905.00	13466.87	-1561.87	2169.39

1) FY 1982 receipts are estimated as if AS43.21 were in effect for the whole year in column 2 then as if AS43.20 were in effect for the whole year in column 3 though each was in effect only half the fiscal year.

2) FY 1982 collections under SB 524 of $668.9m are comprised of $538.2m from AS43.21"OLD SEPARATE ACCT" law and $130.7 from AS43.20 "CURRENT MODIFIED APPORTIONMENT" law.

3) FY 1985 HB353 Corp. Inc. Tax includes $60.3m of AS43.20 already collected through December 31, 1984.

4) FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.

5) Based on 6/85 Mean case price and production assumptions.

TABLE 2a
Calculation of State Petroleum Revenues as a
Percent of Adjusted Production Income
6/85 Forecast Assumptions Mean Case FY 85-05 Using WHV

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3525.22	31.42%
				Pre SB 524	
				Impact SB 524	
82	12958.93	1740.58	11218.35	3525.22	31.42%
83	11941.70	2113.21	9828.49	3270.36	33.27%
84	11327.62	2511.29	8816.33	3148.49	35.71%
85	11382.33	2832.59	8549.74	3161.10	36.97%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	11382.33	2832.59	8549.74	3297.36	38.57%
86	10144.92	3016.23	7128.69	3133.99	43.96%
87	9186.96	3365.90	5821.05	2739.66	47.06%
88	9007.17	3588.61	5418.56	2386.40	44.04%
89	9143.65	3773.47	5370.17	2372.84	44.19%
90	9095.93	3923.57	5172.36	2363.66	45.70%
91	8808.87	3896.45	4912.42	2277.76	46.37%
92	9018.44	3900.45	5117.99	2314.22	45.22%
93	9112.08	3835.75	5276.33	2336.99	44.29%
94	8711.44	3691.57	5019.87	2233.22	44.49%
95	8469.24	3564.66	4904.58	2163.87	44.12%
96	8114.79	3453.17	4661.62	2058.35	44.16%
97	7908.83	3371.45	4537.38	1983.17	43.71%
98	7745.92	3316.04	4429.88	1918.21	43.30%
99	7613.86	3292.00	4321.86	1861.46	43.07%
2000	7505.98	3233.04	4272.94	1803.53	42.21%
01	7058.19	3191.10	3867.09	1646.97	42.59%
02	6540.09	3147.51	3392.58	1468.94	43.30%
03	6137.45	3175.88	2961.57	1311.45	44.28%
04	5800.91	3099.70	2701.21	1185.11	43.87%
05	5368.99	3063.13	2325.86	1051.88	45.23%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3502.40	31.22%
				AS43.20 & 55	
82	12958.93	1740.58	11218.35	3928.80	35.02%
83	11941.70	2113.21	9828.49	3321.58	33.80%
84	11327.62	2511.29	8816.33	3220.43	36.53%
85	11382.33	2832.59	8549.74	3154.10	36.89%
				AS43.20 & 55	
85	11382.33	2832.59	8549.74	3154.10	36.89%
86	10144.92	3016.23	7128.69	2918.12	40.93%
87	9186.96	3365.90	5821.05	2728.41	46.87%
88	9007.17	3588.61	5418.56	2463.54	45.46%
89	9143.65	3773.47	5370.17	2446.11	45.55%
90	9095.93	3923.57	5172.36	2441.63	47.21%
91	8808.87	3896.45	4912.42	2354.81	47.94%
92	9018.44	3900.45	5117.99	2381.93	46.54%
93	9112.08	3835.75	5276.33	2390.22	45.30%
94	8711.44	3691.57	5019.87	2275.33	45.33%
95	8469.24	3564.66	4904.58	2202.06	44.90%
96	8114.79	3453.17	4661.62	2191.17	47.00%
97	7908.83	3371.45	4537.38	2010.93	44.32%
98	7745.92	3316.04	4429.88	1936.69	43.72%
99	7613.86	3292.00	4321.86	1871.94	43.31%
2000	7505.98	3233.04	4272.94	1802.25	42.18%
01	7058.19	3191.10	3867.09	1640.85	42.43%
02	6540.09	3147.51	3392.58	1473.12	43.42%
03	6137.45	3175.88	2961.57	1327.19	44.81%
04	5800.91	3099.70	2701.21	1199.96	44.42%
05	5368.99	3063.13	2325.86	1072.99	46.13%

1) FY 1985 HB353 Corp. Inc. Tax includes $60.8m of AS43.20 already collected through December 31, 1984 and half a year of the new tax.

2) Based on 6/85 Mean case price and production assumptions.

TABLE 2b
Calculation of State Petroleum Revenues as a
and as a Percent of Prod'n & Pipeline Income
6/85 Forecast Assuoptions Mean Case FY 85-05 Using WHV

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3896.85	28.62%
				Pre SB 524	
				Impact SB 524	
82	16455.80	2839.52	13616.28	3896.85	28.62%
83	15469.75	3156.70	12313.06	3644.37	29.60%
84	14955.03	3492.67	11462.37	3544.02	30.92%
85	15135.98	3750.89	11385.10	3569.86	31.36%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	15135.98	3750.89	11385.10	3585.00	31.49%
86	13905.72	3905.70	10000.02	3544.03	35.44%
87	13017.77	4248.71	8769.06	3150.31	35.93%
88	12634.59	4451.25	8183.34	2780.27	33.97%
89	12632.58	4620.60	8011.98	2748.11	34.30%
90	12386.26	4760.52	7625.75	2717.11	35.63%
91	11789.54	4722.70	7066.85	2600.06	36.79%
92	11834.36	4712.14	7122.22	2613.25	36.69%
93	11738.58	4632.28	7106.30	2614.56	36.79%
94	11023.65	4473.66	6550.00	2479.92	37.86%
95	10538.09	4336.33	6201.77	2381.46	38.40%
96	9936.752	4216.39	5720.36	2248.00	39.30%
97	9515.632	4126.62	5389.01	2146.98	39.84%
98	9171.577	4062.83	5108.75	2059.32	40.31%
99	8885.202	4032.89	4852.31	1982.41	40.85%
2000	8645.682	3969.34	4676.34	1906.39	40.77%
01	8025.031	3925.09	4099.94	1729.17	42.18%
02	7343.314	3884.93	3458.38	1529.72	44.23%
03	6811.310	3922.66	2888.65	1352.87	46.83%
04	6367.785	3858.14	2509.65	1209.26	48.18%
05	5850.748	3834.13	2016.62	1059.29	52.53%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3664.40	26.91%
				AS43.20 & 55	
82	16455.80	2839.52	13616.28	4090.80	30.04%
83	15469.75	3156.70	12313.06	3478.98	28.25%
84	14955.04	3492.67	11462.37	3396.43	29.64%
85	15135.99	3750.89	11385.10	3316.10	29.13%
				AS43.20 & 55	
85	15135.98	3750.89	11385.10	3316.10	29.13%
86	13905.72	3905.70	10000.02	3073.89	30.74%
87	13017.77	4248.71	8769.06	2877.95	32.82%
88	12634.59	4451.25	8183.34	2606.85	31.86%
89	12632.58	4620.60	8011.98	2583.19	32.24%
90	12386.26	4760.52	7625.75	2572.68	33.74%
91	11789.54	4722.70	7066.85	2479.43	35.09%
92	11834.36	4712.14	7122.22	2500.31	35.11%
93	11738.58	4632.28	7106.30	2502.37	35.21%
94	11023.65	4473.66	6550.00	2381.25	36.36%
95	10538.09	4336.33	6201.77	2301.75	37.11%
96	9936.752	4216.39	5720.36	2284.63	39.94%
97	9515.632	4126.62	5389.01	2098.16	38.93%
98	9171.577	4062.83	5108.75	2017.69	39.49%
99	8885.202	4032.89	4852.31	1946.71	40.12%
2000	8645.682	3969.34	4676.34	1870.79	40.01%
01	8025.031	3925.09	4099.94	1703.16	41.54%
02	7343.314	3884.93	3458.38	1529.20	44.22%
03	6811.310	3922.66	2888.65	1377.04	47.67%
04	6367.785	3858.14	2509.65	1243.58	49.55%
05	5850.748	3834.13	2016.62	1110.37	55.06%

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1) FY 1985 HB353 Corp. Inc Tax includes $60.8m of AS43.20 already collected through December 1, 1984 and half a year of the new tax.

2) Based on 6/85 Mean case price and production assuoutions.

TABLE 3
Pipeline, Production & Exploration
Income Tax Estimates
(all current FY $)

Fiscal Year	Total Revenue	State Royalty Share	Prod'n& Cons Tax	Total Property Tax	Total Oper'g Costs	Total Depre	Total Acquis Costs	Windfall Profits Tax	Interest Expense Uncap	Exploratn Costs	Admin Costs	Other Deductns	Total Deductns	Total Net Income	Liability------Collections------ HB 353 1)	HB 353 1)	AS 43.20 2)	Diff
82	16455.80	1564.30	1219.03	275.90	939.87	652.58	0.77	2017.66	720.69	190.90	236.20	148.58	7916.41	8539.40	802.70	837.62	130.72	706.90
83	15479.75	1442.73	1098.94	306.55	1100.56	780.16	0.98	1018.38	676.04	204.26	252.30	142.39	7023.30	8446.46	793.97	796.15	236.00	560.15
84	15.04	1370.57	1032.93	357.66	1259.34	998.45	1.09	412.33	614.13	218.56	264.90	136.20	6664.16	8288.87	779.15	782.86	265.10	517.76
85	15135.99	1362.44	1013.86	396.56	1449.17	1093.32	0.80	70.26	565.55	233.86	278.20	130.00	6594.01	8541.97	602.95	797.00	168.60	628.40
85	15135.99	1362.44	1377.52	396.56	1449.17	1093.32	0.80	69.59	565.55	233.86	278.20	130.00	6887.41	8248.58	775.37	581.52	168.60	412.92
86	13905.72	1220.61	1204.74	420.27	1477.66	1224.05	0.76	39.85	541.76	245.55	292.10	123.82	6751.52	7154.20	672.50	698.21	228.07	470.15
87	13017.78	1098.54	979.68	465.05	1599.63	1441.20	7.86	18.80	517.87	257.83	306.70	117.63	6791.98	6225.79	585.22	607.04	241.37	365.67
88	12634.59	1025.54	885.93	501.61	1644.96	1583.60	25.26	9.83	490.28	270.72	322.00	114.43	6664.33	5970.26	561.20	567.21	249.25	317.96
89	12632.59	1017.67	861.33	518.92	1672.48	1698.84	55.27	6.32	466.41	284.26	338.10	105.24	6818.52	5814.06	546.52	550.19	252.48	297.71
90	12386.27	1014.66	840.39	542.76	1760.02	1711.70	93.64	4.14	442.64	298.47	355.00	99.05	6958.33	5427.94	510.23	519.30	254.00	265.30
91	11789.55	983.67	803.23	537.14	1747.62	1653.39	124.08	2.71	418.55	313.57	372.80	92.86	6848.74	4942.81	464.62	476.02	251.48	224.55
92	11834.36	1008.16	810.04	528.09	1763.64	1618.38	129.44	1.72	393.54	329.07	391.40	86.67	6858.43	4975.93	467.74	466.96	248.45	218.51
93	11738.58	1022.99	809.35	515.73	1761.02	1535.91	130.52	0.70	367.83	345.52	411.00	80.48	6780.35	4958.23	466.07	466.49	244.40	222.09
94	11023.66	982.41	562.39	501.06	1727.71	1405.20	126.96	0.03	345.21	362.79	431.50	74.29	6519.52	4504.14	423.39	434.06	236.82	197.24
95	10538.10	958.25	546	484.11	1674.87	1305.73	124.63	0.00	328.97	380.93	453.10	68.10	6314.15	4223.95	397.05	403.64	228.19	175.44
96	9936.75	922.47	530.99	464.38	1649.40	1199.88	113.07	0.00	316.45	399.98	475.70	61.91	6094.23	3842.52	361.20	370.16	236.82	133.34
97	9515.63	904.71	456.78	442.44	1632.22	1116.78	97.80	0.00	304.62	419.98	499.50	55.72	5930.55	3585.08	337.00	343.05	211.35	131.69
98	9171.58	891.76	427.43	418.20	1621.84	1052.52	80.44	0.00	293.02	440.98	524.50	49.53	5800.22	3371.36	316.91	321.93	204.13	117.80
99	8865.20	884.73	402.26	392.51	1619.95	1002.70	70.07	0.00	283.10	463.03	550.70	43.34	5712.39	3172.81	298.24	302.91	197.49	105.42
2000	8645.68	877.78	372.55	365.75	1584.89	949.30	59.65	0.00	273.69	486.18	578.30	37.14	5585.42	3060.26	287.66	290.31	190.00	100.31
01	8025.03	831.91	326.22	313.85	1580.39	879.42	50.65	0.00	265.99	510.49	607.20	30.95	5397.07	2627.96	247.03	257.19	180.10	77.09
02	7343.31	775.51	279.22	262.26	1567.70	812.89	43.16	0.00	262.91	536.01	637.50	24.76	5201.92	2141.39	201.29	212.73	169.31	43.42
03	6811.31	725.47	245.16	211.62	1580.84	762.60	35.11	0.00	263.33	562.81	699.40	18.57	5104.91	1706.40	160.40	170.62	159.82	10.81
04	6367.79	684.66	221.49	161.34	1539.73	719.23	28.51	0.00	264.44	590.95	702.90	12.38	4925.63	1442.16	135.56	141.77	150.55	-8.78
05	5850.75	637.09	201.86	111.27	1507.31	672.99	24.26	0.00	264.88	620.50	738.00	6.19	4784.35	1066.40	100.24	109.07	140.64	-31.57

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1) These estimates assume the tax plan is in effect for the whole year; for FY 1982-85 this is Pre SB 524, for FY 1985-05 this is HB 353.
2) FY82 collections of $130.72m are the actual amounts collected or credited to CY82 liability. The estimate for a full year under AS43.20 in FY82 is $242.5m which would result in a difference of $595.12m as presented in column 4 of Table 1. FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.
3) Based on 6/85 Mean case price and production assumptions.

TABLE 4
All Producing Fields
Income Tax Estimates
(mil current FY $)

Fiscal Year	Oil Prod'n (mil B/D)	Wellhead Value 1) (cur $)	Gas Prod'n (mcf/day)	Gas Price 1) (/mcf)	Total Revenue (cur $)	State Royalty Share	Prod'n Cons Tax	Property Tax	Total Oper'tg Costs	Depre Devel Costs	Amort of Acquis Costs	Windfall Profits Tax	Interest Expense	Explorato Costs (expen'd)	Admin Cost	Other Deductns	Total Deductns	Total Taxable Income	Total Tax Liability	Total Tax Collectns
82	1.6533	21.293	507000	0.590	12959.93	1564.30	1219.03	113.90	710.80	333.93	0.77	2017.66	119.40	190.90	236.20	148.58	6655.47	6303.46	592.53	627.99
83	1.7006	19.340	503000	0.670	11941.70	1442.73	1058.94	149.15	880.56	511.51	0.98	1018.38	121.20	204.26	252.30	142.39	5822.41	6119.30	575.21	579.54
84	1.7183	17.264	505000	0.670	11327.62	1370.57	1032.93	191.65	1038.34	729.80	1.09	412.33	122.40	218.56	264.90	136.20	5518.78	5808.83	546.03	553.33
85	1.7523	17.483	565091	0.971	11382.33	1362.44	1013.86	234.56	1237.67	824.67	0.80	70.26	127.40	233.86	278.20	130.00	5513.71	5868.61	551.65	550.24
85	1.7523	17.483	565091	0.971	11382.33	1362.44	1377.52	234.56	1237.67	824.67	0.80	69.59	127.40	233.86	278.20	130.00	5807.11	5575.22	524.07	393.05
86	1.7008	15.521	537824	1.097	10144.92	1220.81	1204.74	264.50	1266.70	955.46	0.76	39.85	131.60	245.55	292.10	123.82	5706.28	4438.64	417.23	443.94
87	1.7888	13.713	625000	1.700	9186.96	1098.54	979.68	315.51	1367.24	1172.55	7.86	18.60	136.10	257.83	306.70	117.63	5759.63	3427.32	322.17	345.93
88	1.6858	14.108	705650	1.306	9007.17	1025.54	695.93	358.30	1402.65	1314.95	25.26	9.83	138.60	270.72	322.00	114.43	5658.38	3348.79	314.79	316.63
89	1.6171	14.872	714549	1.400	9143.65	1017.67	681.33	381.84	1421.01	1430.19	55.27	6.32	139.40	284.26	338.10	105.24	5834.31	3309.33	311.08	312.00
90	1.5236	15.535	797830	1.570	9695.93	1014.66	640.39	411.91	1494.06	1443.05	93.64	4.14	140.30	298.47	355.60	99.05	5990.53	3105.40	291.91	296.70
91	1.3796	16.431	828950	1.706	8808.87	983.67	603.23	412.52	1467.67	1384.74	124.08	2.71	140.90	313.40	372.60	92.86	5895.87	2913.00	273.82	278.34
92	1.3820	17.691	902485	1.856	9018.44	1008.16	610.04	409.71	1473.64	1349.73	129.44	1.72	141.10	329.07	391.40	86.67	5928.36	3090.08	290.47	286.31
93	1.2133	19.063	920667	1.995	9112.08	1022.99	609.35	403.58	1459.67	1267.26	130.52	0.70	141.30	345.52	411.00	80.49	5871.67	3240.41	304.60	301.07
94	1.0481	20.548	893060	2.149	8711.44	982.41	562.39	395.14	1418.28	1136.55	126.96	0.03	141.20	362.79	431.50	74.29	5631.51	3079.93	289.51	293.28
95	0.9565	22.107	906549	2.270	8469.24	959.25	535.46	384.42	1358.12	1037.08	124.63	0.00	142.70	380.93	453.10	68.10	5442.79	3026.45	284.49	285.74
96	0.8435	23.745	920462	2.395	8114.79	922.47	456.99	370.92	1324.58	931.23	115.67	0.00	146.70	399.98	475.70	61.91	5237.55	2877.24	270.46	273.97
97	0.7449	25.858	936358	2.562	7908.83	904.71	456.78	355.21	1298.82	848.13	97.80	0.00	151.50	419.98	499.50	55.72	5088.15	2820.68	265.14	266.47
98	0.6617	28.124	954349	2.737	7745.92	891.75	427.43	337.20	1279.92	783.87	80.44	0.00	156.80	440.98	524.50	49.53	4972.43	2773.49	260.71	261.82
99	0.5910	30.529	963764	2.987	7613.86	874.73	402.26	317.74	1269.61	736.05	70.07	0.00	162.20	463.03	550.70	43.34	4896.73	2717.13	255.41	256.73
2000	0.5296	33.163	974739	3.244	7505.58	877.78	372.55	297.21	1223.13	660.65	59.65	0.00	168.00	486.18	578.30	37.14	4780.58	2725.40	256.19	255.99
01	0.4497	35.970	890983	3.550	7059.19	831.91	326.22	251.54	1207.04	610.77	50.65	0.00	174.00	510.49	607.20	30.93	4600.77	2457.42	231.00	237.30
02	0.3739	38.662	879667	3.847	6549.09	775.51	279.22	208.18	1181.44	544.24	43.16	0.00	180.40	536.01	637.50	24.76	4408.42	2131.67	200.38	208.03
03	0.3140	41.858	879601	4.172	6137.45	725.47	245.16	181.77	1178.94	493.95	35.11	0.00	187.10	562.81	669.40	18.57	4308.28	1829.17	171.94	179.05
04	0.2645	45.364	860541	4.518	5800.91	684.66	221.47	157.72	1170.38	455.58	28.51	0.00	194.00	593.95	702.90	12.38	4123.57	1677.34	157.67	161.24
05	0.2158	49.264	843787	4.896	5388.99	637.09	201.86	135.69	1168.44	424.34	24.26	0.00	201.40	620.50	733.00	6.19	3975.97	1413.02	132.82	137.04

1) These prices are weighted average wellhead values derived from the various values at the N. Slope and Cook Inlet fields evaluated in this study.

TABLE 5
Trans Alaska Pipeline
Income Tax Estimates
(mil current FY $)

Fiscal Year	Pipeline Thruput (mil B/D)	Tariff ($/B)	Total Revenue	Operat'g Costs/ Year	Amort & Deprec	Uncap Interest	Property Tax	Total Deduction	Net Income	Tax Liability (9.4%)
82	1.5600	6.11	3496.88	229.00	268.65	601.29	162.00	1260.94	2235.94	210.18
83	1.6300	5.93	3528.05	220.00	268.65	554.84	157.40	1200.89	2327.16	218.75
84	1.6536	6.01	3627.42	221.00	268.65	491.73	166.00	1147.38	2480.04	233.12
85	1.7140	6.00	3753.66	211.50	268.65	438.15	162.00	1080.30	2673.36	251.30
86	1.7173	6.00	3760.80	210.96	268.65	409.86	155.77	1045.24	2715.56	255.26
87	1.7492	6.00	3830.82	232.39	268.65	381.77	149.54	1032.35	2798.47	263.06
88	1.6564	6.00	3627.42	242.31	268.65	351.68	143.31	1005.95	2621.47	246.42
89	1.5931	6.00	3488.94	251.47	268.65	327.01	137.08	984.21	2504.73	235.44
90	1.5024	6.00	3290.34	265.96	268.65	302.34	130.85	967.80	2322.54	218.32
91	1.3610	6.06	2980.68	279.95	268.65	277.65	124.62	950.87	2029.81	190.80
92	1.2858	6.00	2815.92	290.60	268.65	252.44	118.38	930.07	1885.85	177.27
93	1.1993	6.00	2626.50	301.35	268.65	226.53	112.15	908.68	1717.82	161.48
94	1.0558	6.00	2312.22	309.43	268.65	204.01	105.92	888.01	1424.21	133.88
95	0.9447	6.00	2068.86	316.75	268.65	186.27	99.69	871.36	1197.50	112.57
96	0.8319	6.00	1821.96	324.82	268.65	169.75	93.46	856.68	965.28	90.74
97	0.7337	6.00	1606.80	333.40	268.65	153.12	87.23	842.40	764.40	71.85
98	0.6510	6.00	1425.66	341.92	268.65	136.22	81.00	827.79	597.87	56.20
99	0.5805	6.00	1271.34	351.34	268.65	120.90	74.77	815.66	455.68	42.83
2000	0.5204	6.00	1139.70	361.76	268.65	105.69	68.54	804.84	334.86	31.48
01	0.4415	6.00	966.84	373.35	268.65	91.99	62.31	796.30	170.54	16.03
02	0.3668	6.00	803.22	386.26	268.65	82.51	56.08	793.50	9.72	0.91
03	0.3077	6.00	673.86	401.90	268.65	76.23	49.85	796.63	-122.77	-11.54
04	0.2588	6.00	566.88	419.35	268.65	70.44	43.62	802.06	-235.18	-22.11
05	0.2108	6.00	461.76	438.87	268.65	63.48	37.38	808.38	-346.62	-32.58

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1) No gas production considered (26 TCF).
2) No TAPS settlement.
3) Some amount of total crude taken off at N. Pole i.e. does not go to Valdez.
4) Based on 6/85 Mean case price and production assumptions.
5) Seal Is. excluded.

ASSUMPTIONS:

Property taxes per AS43.56 @2% gross.

TABLE 6
WINDFALL PROFITS TAX DEDUCTION
(mil current FY $)

DEDUCTION FROM FY TAXABLE INCOME

Fiscal Year	Sadlerochit	Cook Inlet	Total	Impact on FY Tax Liability (Total * .094)
Under Pre-SB 524				
	a)			
82	1750.61	267.05	2017.66	189.66
83	848.78	169.60	1018.38	95.73
84	289.25	123.08	412.33	38.76
85	8.93	61.33	70.26	6.60
Under HB 353				
	b)			
85	8.51	61.09	69.60	6.54
86	-0-	39.85	39.85	3.75
87	-0-	18.80	18.80	1.77
88	-0-	9.83	9.83	.92
89	-0-	6.32	6.32	.59
90	-0-	4.14	4.14	.39
91	-0-	2.71	2.71	.25
92	-0-	1.72	1.72	.16
93	-0-	.70	.70	.07
94	-0-	.03	.03	-0-

Note:

1/ Based on 6/85 Mean case price and production assumptions.

2/ Windfall Profits Tax is phased out and no longer in effect in FY 1995 and thereafter.

3/ The reason for the slight difference in FY 85 under Pre-SB 524 compared to HB 353 is the difference in the Oil Severance Tax law and thus, the severance tax adjustment under the WPT.

a) For FY 1982 through 1985, these impacts are included in Tables 3 and 4 under the Pre-SB 524 separate accounting corporate tax. If the WPT was not a deduction for those years, the total tax liability columns would have been increased by these amounts.

b) For FY 1982 through 2005, these impacts are not included in Tables 3 and 4 under the HB 353 separate accounting corporate tax. If the WPT was a deduction for these years, the total tax liability columns would be reduced by these amounts. In FY 1985, the reduction would be approximately one half the amount because HB 353 goes into effect midway through the fiscal year.

HB 353 AND SB 524
ANALYSIS
JUNE, 1985
30% CASE ASSUMPTIONS

SUMMARY TABLES

TABLE 1
Old Law (Pre SB 524)
Current Law (AS43.20 & AS 43.55)
Proposed Law (HB 353)
(all current FY $)

Fiscal Year	To. Corp Inc Tax Collections Pre SB 524	AS 43.20	Diff	Total Prodn Tax Liability Pre SB 524	AS 43.55	Diff	Total Gain or Loss
82	837.62	242.50	-595.12 1)	1219.03	1581.70	362.67	-232.45
			Impact SB 524			Impact SB 524	Impact SB 524
82	837.62	668.90	-168.72 2)	1219.03	1581.70	362.67	193.95
83	796.15	236.00	-560.15	1098.94	1493.70	394.76	-165.39
84	782.96	265.10	-517.76	1032.93	1393.10	360.17	-157.59
85	797.00	168.60	-628.40	1015.36	1388.50	374.64	-253.76
			Impact HB 353	existing		Impact HB 353	Impact HB 353
	HB 353			AS 43.55			
85	448.48	168.60	279.88 3)	1388.50	1388.50	0.00	279.88
86	684.73	223.67	461.06	1172.84	1172.84	0.00	461.06
				HB 353			
87	563.79	232.71	331.08	904.34	939.98	-85.64	245.44
88	515.28	238.38	276.90	638.67	773.71	-135.04	141.86
89	491.39	241.26	250.13	610.81	737.88	-127.07	123.06
90	456.84	241.28	215.56	586.91	703.35	-116.44	99.12
91	410.91	238.09	172.82	541.91	642.15	-100.24	72.58
92	401.05	235.48	165.57	546.70	646.31	-99.61	65.96
93	401.31	232.44	168.87	552.78	639.54	-86.76	82.11
94	373.10	225.67	147.43	507.40	595.90	-88.50	58.93
95	344.91	217.58	127.33	480.40	562.13	-81.73	45.60
96	316.61	209.73	106.88	443.18	516.64	-73.46	33.42
97	292.49	202.00	90.49	415.23	484.75	-69.52	20.97
98	270.06	194.51	75.55	388.95	451.24	-62.29	13.26
99	247.16	187.15	60.01	361.51	418.64	-57.13	2.88
2000	226.90	178.63	48.27	332.77	384.15	-51.38	-3.11
01	184.23	167.79	16.45	283.19	328.46	-45.27	-28.82
02	141.64	156.78	-15.14	245.12	278.92	-33.80	-48.94
03	102.89	147.24	-45.15	214.35	243.63	-29.28	-74.43
04	70.65	137.62	-66.97	193.20	217.30	-19.10	-86.07
05	29.57	126.56	-96.99	181.65	199.81	-18.16	-115.15
SUM85-05	6973.24	4203.18	2770.05	10995.41	12375.83	-1380.42	1389.63

1) FY 1982 receipts are estimated as if AS43.21 were in effect for the whole year in colum 2 then as if AS43.20 were in effect for the whole year in colum 3 though each was in effect only half the fiscal year.

2) FY 1982 collections under SB 524 of $668.9m are comprised of $538.2m from AS43.21"OLD SEPARATE ACCT" law and $130.7 from AS43.20 "CURRENT MODIFIED APPORTIONMENT" law.

3) FY 1985 HB353 Corp. Inc. Tax includes $60.8m of AS43.20 already collected through December 31, 1984.

4) FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.

5) Based on 6/85 30% case price and production assumptions.

TABLE 2a
Calculation of State Petroleum Revenues as a
Percent of Adjusted Production Income
6/85 Forecast Assumptions 30% Case FY 85-05 Using WHV

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3525.22	31.42%
				Pre SB 524	
				Impact SB 524	
82	12958.93	1740.58	11218.35	3525.22	31.42%
83	11941.70	2113.21	9828.49	3270.36	33.27%
84	11327.62	2511.29	8816.33	3148.49	35.71%
85	11382.33	2832.59	8549.74	3161.10	36.97%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	11382.33	2832.59	8549.74	3297.36	38.57%
86	9837.72	3015.48	6872.24	3055.24	44.46%
87	8471.80	3356.83	5114.97	2532.10	49.50%
88	8329.60	3543.97	4765.63	2211.37	46.21%
89	8353.24	3632.71	4720.52	2186.06	46.31%
90	8258.78	3741.13	4517.65	2166.34	47.95%
91	7904.70	3688.01	4216.70	2064.21	48.95%
92	8107.26	3709.46	4397.81	2094.52	47.63%
93	8221.24	3673.21	4548.02	2123.74	46.70%
94	7885.09	3559.52	4325.56	2028.93	46.91%
95	7646.27	3432.19	4214.09	1957.90	46.46%
96	7363.98	3335.04	4028.95	1867.70	46.36%
97	7169.51	3252.94	3916.57	1796.94	45.88%
98	6955.00	3173.31	3781.69	1724.47	45.60%
99	6738.45	3115.29	3623.15	1649.99	45.54%
2000	6513.93	3032.96	3480.97	1573.83	45.21%
01	5912.10	2940.61	2971.49	1388.82	46.74%
02	5485.48	2915.17	2570.31	1232.63	47.96%
03	5109.57	2945.74	2163.83	1091.16	50.43%
04	4743.44	2867.67	1875.77	974.30	51.94%
05	4269.43	2865.16	1404.27	830.15	59.12%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3502.40	31.22%
				AS43.20 & 55	
82	12958.93	1740.58	11218.35	3928.80	35.02%
83	11941.70	2113.21	9828.49	3321.58	33.80%
84	11327.62	2511.29	8816.33	3220.43	36.53%
85	11382.33	2832.59	8549.74	3154.10	36.89%
				AS43.20 & 55	
85	11382.33	2832.59	8549.74	3154.10	36.89%
86	9837.72	3015.48	6872.24	2848.45	41.45%
87	8471.80	3356.83	5114.97	2547.16	49.80%
88	8329.60	3543.97	4785.63	2316.57	48.41%
89	8353.24	3632.71	4720.52	2290.29	48.52%
90	8258.78	3741.13	4517.65	2274.97	50.36%
91	7904.70	3688.01	4216.70	2173.54	51.55%
92	8107.26	3709.46	4397.81	2194.70	49.90%
93	8221.24	3673.21	4548.02	2194.89	48.26%
94	7885.09	3559.52	4325.56	2101.34	48.58%
95	7646.27	3432.19	4214.09	2021.91	47.98%
96	7363.98	3335.04	4028.95	2019.17	50.12%
97	7169.51	3252.94	3916.57	1847.31	47.17%
98	6955.00	3173.31	3781.69	1766.06	46.70%
99	6738.45	3115.29	3623.15	1687.16	46.57%
2000	6513.93	3032.96	3480.97	1604.07	46.08%
01	5912.10	2940.61	2971.49	1428.57	48.08%
02	5485.48	2915.17	2570.31	1277.36	49.70%
03	5109.57	2945.74	2163.83	1148.81	53.09%
04	4743.44	2867.67	1875.77	1032.52	55.05%
05	4269.43	2865.16	1404.27	906.04	64.52%

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1) FY 1985 HB353 Corp. Inc. Tax includes $60.8m of AS43.20 already collected through December 31, 1984 and half a year of the new tax.

2) Based on 6/85 30% case price and production assumptions.

TABLE 2b
Calculation of State Petroleum Revenues as a
and as a Percent of Prod'n & Pipeline Income
6/85 Forecast Assumptions 30% Case FY 85-05 Using WHV

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3896.85	28.62%
				Pre SB 524	
				Impact SB 524	
82	16455.80	2839.52	13616.28	3896.85	28.62%
83	15469.75	3156.70	12313.06	3644.37	29.60%
84	14955.03	3492.67	11462.37	3544.02	30.92%
85	15135.98	3750.89	11385.10	3569.86	31.36%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	15135.98	3750.89	11385.10	3585.00	31.49%
86	13648.51	3904.95	9743.57	3465.28	35.56%
87	12293.67	4239.30	8054.38	2942.14	36.53%
88	11908.05	4404.62	7503.44	2601.74	34.67%
89	11697.09	4473.67	7223.42	2550.43	35.31%
90	11377.10	4570.41	6806.69	2504.94	36.80%
91	10708.14	4505.98	6202.17	2370.74	38.22%
92	10766.04	4513.45	6252.60	2379.04	38.05%
93	10718.43	4463.08	6255.35	2389.15	38.19%
94	10099.08	4336.29	5762.79	2266.19	39.32%
95	9623.390	4198.63	5424.77	2167.20	39.95%
96	9118.502	4094.19	5024.32	2050.85	40.82%
97	8719.606	4004.47	4715.14	1955.51	41.47%
98	8319.520	3915.96	4403.56	1860.32	42.25%
99	7936.706	3850.96	4085.74	1764.81	43.19%
2000	7567.890	3762.81	3805.08	1669.50	43.88%
01	6769.499	3665.94	3103.56	1462.05	47.11%
02	6187.359	3643.99	2543.37	1284.50	50.50%
03	5687.426	3684.00	2003.43	1124.23	56.12%
04	5211.317	3616.86	1594.46	990.07	62.09%
05	4618.090	3624.93	993.16	828.28	83.40%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3664.40	26.91%
				AS43.20 & 55	
82	16455.80	2839.52	13616.28	4090.80	30.04%
83	15469.75	3156.70	12313.06	3478.98	28.25%
84	14955.04	3492.67	11462.37	3386.43	29.54%
85	15135.99	3750.89	11385.10	3316.10	29.13%
				AS43.20 & 55	
85	15135.98	3750.89	11385.10	3316.10	29.13%
86	13648.51	3904.95	9743.57	3004.22	30.83%
87	12293.67	4239.30	8054.38	2696.70	33.48%
88	11908.05	4404.62	7503.44	2459.88	32.78%
89	11697.09	4473.67	7223.42	2427.37	33.60%
90	11377.10	4570.41	6806.69	2405.82	35.35%
91	10708.14	4505.98	6202.17	2298.16	37.05%
92	10766.04	4513.45	6252.60	2313.08	36.99%
93	10718.43	4463.08	6255.35	2307.04	36.88%
94	10099.08	4336.29	5762.79	2207.26	38.30%
95	9623.390	4198.63	5424.77	2121.60	39.11%
96	9118.502	4094.19	5024.32	2112.63	42.05%
97	8719.606	4004.47	4715.14	1934.54	41.03%
98	8319.520	3915.96	4403.56	1847.06	41.94%
99	7936.706	3850.96	4085.74	1761.93	43.12%
2000	7567.890	3762.81	3805.08	1672.61	43.96%
01	6769.499	3665.94	3103.56	1490.88	48.04%
02	6187.359	3643.99	2543.37	1333.44	52.43%
03	5687.426	3684.00	2003.43	1198.66	59.83%
04	5211.317	3616.86	1594.46	1076.14	67.49%
05	4618.090	3624.93	993.16	943.42	94.99%

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1) FY 1985 HB353 Corp. Inc Tax includes $60.8m of AS43.20 already collected through December 1, 1984 and half a year of the new tax.

2) Based on 6/85 30% case price and production assumptions.

TABLE 3
Pipeline, Production & Exploration
Income Tax Estimates
(mil current FY $)

Fiscal Year	Total Revenue	State Royalty Share	Prod'n& Cons Tax	Total Property Tax	Total Oper'g Costs	Total Depre	Total Acquis Costs	Windfall Profits Tax	Interest Expense Uncap	Exploratn Costs	Admin Costs	Other Deductns	Total Deductns	Total Net Income	Liability HB 353 1)	Collections HB 353 1)	Collections AS 43.20 2)	Diff
82	16455.80	1564.30	1219.03	275.90	939.80	602.58	0.77	2017.66	720.69	190.90	236.20	148.58	7916.41	8539.40	802.70	837.62	130.72	706.90
83	15469.75	1442.73	1098.94	306.55	1100.56	780.16	0.98	1018.38	676.04	204.26	252.30	142.39	7023.30	8446.46	793.97	796.15	236.00	560.15
84	14955.04	1370.57	1032.93	357.66	1259.34	998.45	1.09	412.33	614.13	218.56	264.90	136.20	6666.16	8288.87	779.15	782.86	265.10	517.76
85	15135.99	1362.44	1013.86	396.56	1449.17	1093.32	0.80	70.26	565.55	233.86	278.20	130.00	6594.01	8541.97	802.95	797.00	168.60	628.40
85	15135.99	1362.44	1377.52	396.56	1449.17	1093.32	0.80	69.59	565.55	233.86	278.20	130.00	6887.41	8248.58	775.37	581.52	168.60	412.92
86	13648.52	1187.44	1172.84	420.27	1477.66	1224.05	0.76	35.96	541.76	244.80	292.10	123.82	6685.50	6963.02	654.52	684.73	223.67	461.06
87	12293.68	1008.96	904.34	465.05	1597.00	1437.62	6.25	10.87	517.87	256.24	306.70	117.63	6617.65	5676.03	533.55	563.79	232.71	331.08
88	11908.06	946.18	638.67	501.61	1629.36	1562.56	17.75	4.06	490.28	268.23	322.00	114.43	6491.08	5416.98	509.20	515.28	238.38	276.90
89	11697.10	929.31	610.81	518.92	1625.11	1624.89	33.16	2.14	466.41	280.77	338.10	105.24	6532.71	5164.38	485.45	491.39	241.26	250.13
90	11377.10	922.19	586.91	539.00	1702.64	1619.49	57.70	0.51	442.64	293.90	355.00	99.05	6618.51	4758.59	447.31	456.84	241.28	215.56
91	10708.14	685.09	541.91	532.83	1686.99	1546.15	80.98	0.00	418.55	307.65	372.80	92.86	6465.81	4242.34	398.78	410.91	238.09	172.82
92	10766.04	908.04	546.70	523.25	1709.49	1516.09	94.23	0.00	393.54	322.03	391.40	86.67	6491.44	4274.61	401.81	401.05	235.48	165.57
93	10718.44	924.67	552.78	510.39	1715.39	1448.71	102.58	0.00	367.83	337.09	411.00	80.48	6450.92	4267.51	401.15	401.31	232.44	168.87
94	10099.09	690.42	507.40	495.27	1691.98	1333.24	107.22	0.00	345.21	352.86	431.50	74.29	6229.38	3869.70	363.75	373.10	225.67	147.43
95	9623.39	863.98	480.40	477.91	1640.12	1230.56	108.41	0.00	328.97	369.36	453.10	68.10	6020.92	3602.48	338.63	344.91	217.58	127.33
96	9118.50	833.24	443.18	457.82	1621.89	1127.87	103.73	0.00	316.45	386.63	475.70	61.91	5828.43	3290.08	309.27	316.61	225.67	90.93
97	8719.61	812.20	415.23	435.59	1606.92	1035.88	97.12	0.00	304.62	404.71	499.50	55.72	5667.49	3052.12	286.90	292.49	202.00	90.49
98	8319.52	769.94	388.95	411.37	1592.93	947.57	84.77	0.00	293.02	423.64	524.50	49.53	5506.22	2813.30	264.45	270.06	194.51	75.55
99	7936.71	770.14	361.51	386.00	1584.30	871.20	74.87	0.00	283.10	443.45	550.70	43.34	5368.61	2568.09	241.40	247.16	187.15	60.01
2000	7567.89	750.23	332.77	359.60	1542.66	802.43	64.20	0.00	273.69	464.19	578.30	37.14	5205.41	2362.48	222.07	226.90	178.63	48.27
01	6769.50	687.20	283.19	307.43	1513.33	709.22	53.36	0.00	265.99	485.69	607.20	30.95	4943.76	1825.74	171.62	184.23	167.79	16.45
02	6187.36	640.81	245.12	256.93	1516.82	647.61	45.77	0.00	262.91	508.62	637.50	24.76	4786.85	1400.51	131.65	141.64	156.78	-15.14
03	5687.43	601.02	214.35	206.77	1533.59	598.56	38.15	0.00	263.33	532.40	699.40	18.57	4706.14	981.29	92.24	102.09	147.24	-45.15
04	5211.32	564.20	198.20	157.02	1469.05	559.16	31.62	0.00	264.64	557.30	702.90	12.38	4536.28	675.04	63.45	70.65	137.62	-66.97
05	4618.09	509.52	181.65	107.53	1494.37	511.66	26.27	0.00	264.88	583.36	738.00	6.19	4423.63	194.46	18.28	29.57	126.56	-96.99

1) These estimates assume the tax plan is in effect for the whole year; for FY 1982-85 this is Pre SB 524, for FY 1985-05 this is HB 353.
2) FY82 collections of $130.72m are the actual amounts collected or credited to CY82 liability. The estimate for a full year under AS43.20 in FY82 is $242.5m which would result in a difference of $595.12m as presented in colum 4 of Table I. FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.
3) Based on 6/85 30Y case price and production assumptions.

TABLE 4
All Producing Fields
Income Tax Estimates
(mil current FY $)

Fiscal Year	Oil Prod'n (mil B/D)	Wellhead Value 1) (cur $)	Gas Prod'n (mcf/day)	Gas Price 1) ($/mcf)	Total Revenue (cur $)	State Royalty Share	Prod'n Cons Tax	Property Tax	Total Oper'tg Costs	Depr Devel Costs	Amort of Acquis Costs	Windfall Profits Tax	Interest Expense	Explorato Costs (expen'd)	Admin Cost	Other Deductns	Total Deductns	Total Taxable Income	Total Tax Liability	Total Tax Collectns
82	1.6533	21.293	507000	0.590	12958.93	1564.30	1219.03	113.90	710.80	333.93	0.77	2017.65	119.40	190.90	236.20	148.58	6655.47	6303.46	592.53	627.99
83	1.7006	19.040	503000	0.670	11941.70	1442.73	1068.94	149.15	880.56	511.51	0.98	1018.38	121.20	204.26	252.30	142.39	5822.41	6119.30	575.21	579.54
84	1.7183	17.864	505300	0.670	11327.62	1370.57	1032.93	191.66	1038.34	729.80	1.09	412.33	122.40	218.56	264.90	136.20	5518.78	5808.83	546.03	553.33
85	1.7523	17.483	565091	0.971	11382.33	1362.44	1013.86	234.56	1237.67	824.67	0.80	70.26	127.40	233.86	278.20	130.00	5513.71	5868.61	551.65	550.24
85	1.7523	17.483	565091	0.971	11382.33	1362.44	1377.52	234.56	1237.67	824.67	0.80	69.59	127.40	233.86	278.20	130.00	5807.11	5575.22	524.07	393.05
86	1.7528	15.119	537624	1.097	9887.72	1187.44	1172.84	264.50	1266.70	955.40	0.76	35.96	131.90	244.80	292.10	123.82	5640.26	4247.46	399.26	430.46
87	1.7767	12.642	625030	1.200	8471.80	1008.96	904.34	315.51	1364.95	1158.97	6.25	10.87	136.10	256.24	306.70	117.63	5585.64	2886.16	271.30	303.29
88	1.6815	13.181	705650	1.306	8329.60	946.18	638.67	358.30	1369.04	1293.91	17.75	4.06	138.60	268.23	322.00	114.43	5487.12	2842.48	267.19	268.22
89	1.5509	14.111	714549	1.400	8353.24	929.31	610.81	381.84	1379.81	1356.24	33.16	2.14	139.40	280.77	336.10	105.24	5554.67	2798.56	263.06	264.10
90	1.4450	14.792	797830	1.570	8258.78	922.19	586.91	409.15	1444.35	1350.84	57.70	0.51	140.30	293.90	355.00	99.05	5658.38	2600.40	244.44	249.09
91	1.2987	15.548	858950	1.706	7904.70	885.09	541.91	408.21	1415.32	1277.50	80.98	0.00	140.90	307.65	372.80	92.86	5523.22	2381.49	223.86	229.00
92	1.2362	16.693	902485	1.856	8107.26	908.04	546.70	404.87	1426.59	1247.44	94.23	0.00	141.10	322.03	391.40	86.67	5569.07	2538.20	238.59	234.91
93	1.1542	17.924	920067	1.995	8221.24	924.67	552.78	398.24	1420.70	1180.06	102.59	0.00	141.30	337.09	411.00	80.48	5548.90	2672.33	251.20	248.05
94	1.0233	19.236	893060	2.149	7865.09	890.42	507.40	389.35	1387.87	1064.59	107.22	0.00	141.20	352.86	431.50	74.29	5346.69	2538.39	238.61	241.76
95	0.9146	20.654	906549	2.270	7646.27	863.98	480.40	378.22	1329.60	961.91	108.41	0.00	142.70	369.36	453.10	68.10	5154.79	2491.49	234.20	235.30
96	0.8127	22.114	920462	2.395	7363.98	833.24	443.18	364.36	1301.14	859.22	103.73	0.00	146.70	386.63	475.70	61.91	4975.82	2388.17	224.49	226.92
97	0.7190	23.983	936358	2.562	7169.51	812.20	415.23	348.36	1277.16	767.23	97.12	0.00	151.50	404.71	499.50	55.72	4828.73	2340.78	220.03	221.15
98	0.6318	25.944	954349	2.737	6955.00	789.94	388.95	330.37	1255.15	676.92	84.77	0.00	156.80	423.64	524.50	49.53	4682.57	2272.43	213.61	215.21
99	0.5576	28.054	943764	2.987	6738.45	770.14	361.51	311.23	1238.18	602.55	74.87	0.00	162.20	443.45	550.70	43.34	4558.17	2180.27	204.95	207.11
2000	0.4905	30.268	924739	3.244	6513.93	750.23	332.77	291.08	1187.35	533.78	64.20	0.00	168.00	464.19	578.30	37.14	4407.02	2106.91	198.05	199.77
01	0.3597	32.611	890983	3.550	5912.10	687.20	283.19	245.12	1148.61	440.57	53.36	0.00	174.00	485.69	607.20	30.95	4156.12	1755.98	165.06	173.31
02	0.3277	35.304	899667	3.847	5465.48	640.81	245.12	200.85	1139.16	378.96	45.77	0.00	180.40	508.62	637.50	24.76	4001.95	1483.53	139.45	145.65
03	0.2702	38.227	879601	4.172	5109.57	601.02	214.35	156.92	1140.21	329.91	39.15	0.00	187.10	532.40	669.40	18.57	3918.03	1191.54	112.00	118.87
04	0.2193	41.539	860541	4.518	4743.44	564.20	198.20	113.40	1078.95	290.51	31.62	0.00	194.60	557.20	702.90	12.38	3743.47	999.97	94.00	98.50
05	0.1642	46.078	843787	4.896	4269.43	509.52	181.65	70.15	1066.73	243.21	26.27	0.00	201.40	583.36	738.00	6.19	3626.48	642.95	60.44	68.83

1) These prices are weighted average wellhead values derived from the various values at the N. Slope and Cook Inlet fields evaluated in this study.

TABLE 5
Trans Alaska Pipeline
Income Tax Estimates
(oil current FY $)

Fiscal Year	Pipeline Thruput (mil B/D)	Tariff ($/B)	Total Revenue	Operat'g Costs/ Year	Amort & Deprec	Uncap Interest	Property Tax	Total Deduction	Net Income	Tax Liability (9.4%)
82	1.5680	6.11	3496.88	229.00	268.65	601.29	162.00	1260.94	2235.94	210.18
83	1.6300	5.93	3528.05	220.00	268.65	554.84	157.40	1200.89	2327.16	218.75
84	1.6536	6.01	3627.42	221.00	268.65	491.73	166.00	1147.38	2480.04	233.12
85	1.7140	6.00	3753.66	211.50	268.65	438.15	162.00	1080.30	2673.36	251.30
86	1.7173	6.00	3760.80	210.96	268.65	409.86	155.77	1045.24	2715.56	255.26
87	1.7452	6.00	3821.88	232.05	268.65	381.77	149.54	1032.01	2789.87	262.25
88	1.6340	6.00	3578.46	240.32	268.65	351.68	143.31	1003.96	2574.50	242.00
89	1.5269	6.00	3343.86	245.30	268.65	327.01	137.08	978.04	2365.82	222.39
90	1.4239	6.00	3118.32	258.29	268.65	302.34	130.85	960.13	2158.19	202.87
91	1.2801	6.00	2803.44	271.67	268.65	277.65	124.62	942.59	1860.85	174.92
92	1.2141	6.00	2658.78	282.90	268.65	252.44	118.38	922.37	1736.41	163.22
93	1.1403	6.00	2497.20	294.69	268.65	226.53	112.15	902.02	1595.18	149.95
94	1.0110	6.00	2214.00	304.11	268.65	204.01	105.92	882.69	1331.31	125.14
95	0.9028	6.00	1977.12	311.52	268.65	186.27	99.69	866.13	1110.99	104.43
96	0.8012	6.00	1754.52	320.75	268.65	169.75	93.46	852.61	901.91	84.78
97	0.7078	6.00	1550.10	329.76	268.65	153.12	87.23	838.76	711.34	66.87
98	0.6231	6.00	1364.52	337.78	268.65	136.22	81.00	823.65	540.87	50.84
99	0.5472	6.00	1198.26	346.12	268.65	120.90	74.77	810.44	387.82	36.46
2000	0.4813	6.00	1053.96	355.31	268.65	105.89	68.54	798.39	255.57	24.02
01	0.3915	6.00	857.40	364.69	268.65	91.99	62.31	787.64	69.76	6.56
02	0.3205	6.00	701.88	377.66	268.65	82.51	56.08	784.90	-83.02	-7.80
03	0.2639	6.00	577.86	393.38	268.65	76.23	49.85	788.11	-210.25	-19.76
04	0.2136	6.00	467.88	410.10	268.65	70.44	43.62	792.81	-324.93	-30.54
05	0.1592	6.00	348.66	427.64	268.65	63.48	37.38	797.15	-448.49	-42.16

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1) No gas production considered (26 TCF).
2) No TAPS settlement.
3) Some amount of total crude taken off at N. Pole i.e. does not go to Valdez.
4) Based on 6/85 30% case price and production assumptions.
5) Seal Is. excluded.

ASSUMPTIONS:

Property taxes per AS43.56 @2% gross.

TABLE 6
WINDFALL PROFITS TAX DEDUCTION
(mil current FY $)

DEDUCTION FROM FY TAXABLE INCOME

Fiscal Year	Sadlerochit	Cook Inlet	Total	Impact on FY Tax Liability (Total * .094)
Under Pre-SB 524				
	a)			
82	1750.61	267.05	2017.66	189.66
83	848.78	169.60	1018.38	95.73
84	289.25	123.08	412.33	38.76
85	8.93	61.33	70.26	6.60
Under HB 353				
	b)			
85	8.51	61.09	69.60	6.54
86	-0-	35.96	35.96	3.38
87	-0-	10.87	10.87	1.02
88	-0-	4.06	4.06	.38
89	-0-	2.14	2.14	.20
90	-0-	.51	.51	.05
91	-0-	-0-	-0-	-0-
92	-0-	-0-	-0-	-0-
93	-0-	-0-	-0-	-0-
94	-0-	-0-	-0-	-0-

Note:

1/ Based on 6/85 30% case price and production assumptions.

2/ Windfall Profits Tax is phased out and no longer in effect in FY 1995 and thereafter.

3/ The reason for the slight difference in FY 85 under Pre-SB 524 compared to HB 353 is the difference in the Oil Severance Tax law and thus, the severance tax adjustment under the WPT.

a) For FY 1982 through 1985, these impacts are included in Tables 3 and 4 under the Pre-SB 524 separate accounting corporate tax. If the WPT was not a deduction for those years, the total tax liability columns would have been increased by these amounts.

b) For FY 1982 through 2005, these impacts are not included in Tables 3 and 4 under the HB 353 separate accounting corporate tax. If the WPT was a deduction for these years, the total tax liability columns would be reduced by these amounts. In FY 1985, the reduction would be approximately one half the amount because HB 353 goes into effect midway through the fiscal year.

HB 353 AND SB 524
ANALYSIS
JUNE, 1985
70% CASE ASSUMPTIONS

SUMMARY TABLES

TABLE 1
Old Law (Pre SB 524)
Current Law (AS43.20 & AS 43.55)
Proposed Law (HB 353)

(mil current FY $)

Fiscal Year	To. Corp Inc Tax Collections Pre SB 524	AS 43.20	Diff	Total Prodn Tax Liability Pre SB 524	AS 43.55	Diff	Total Gain or Loss
82	837.62	242.50	-595.12 1) Impact SB 524	1219.03	1581.70	362.67 Impact SB 524	-232.45 Impact SB 524
82	837.62	668.90	-168.72 2)	1219.03	1581.70	362.67	193.95
83	796.15	236.00	-560.15	1093.94	1493.70	394.76	-165.39
84	782.86	265.10	-517.76	1032.93	1393.10	360.17	-157.59
85	797.00	188.60	-628.40 Impact HB 353	1013.86 existing AS 43.55	1388.50	374.64 Impact HB 353	-253.76 Impact HB 353
	HB 353						
85	448.48	168.60	279.88 3)	1388.50	1388.50	0.00	279.88
86	723.72	235.73	487.99	1262.27	1262.27	0.00	487.99
				HB 353			
87	664.57	260.61	403.96	1076.73	1180.56	-103.83	300.13
88	652.24	286.69	365.54	785.41	949.86	-164.45	201.09
89	666.33	305.76	360.57	778.54	930.19	-151.65	208.92
90	670.13	314.61	355.52	784.53	927.21	-142.68	212.84
91	644.76	313.14	331.61	749.98	872.96	-122.98	208.63
92	652.14	311.00	341.14	768.16	894.45	-126.29	214.85
93	664.12	306.83	357.23	772.90	912.04	-139.14	218.14
94	633.70	298.04	335.66	718.76	844.67	-125.91	209.75
95	604.66	287.54	317.12	691.55	819.80	-128.25	188.87
96	586.06	276.00	290.06	636.25	755.74	-119.49	170.57
97	531.12	263.02	268.09	588.58	700.65	-112.07	155.02
98	499.12	249.03	250.09	535.28	635.29	-100.01	150.08
99	464.59	234.66	229.93	481.42	567.82	-86.40	143.53
2000	429.55	219.24	210.31	426.21	502.15	-75.94	134.37
01	368.43	201.62	166.81	354.12	415.11	-60.99	105.82
02	297.67	183.82	113.85	285.39	333.00	-47.61	66.24
03	228.30	167.72	60.58	237.25	270.28	-33.63	26.95
04	158.93	152.99	5.94	195.90	221.31	-25.41	-19.47
05	103.98	139.26	-35.28	173.46	194.21	-20.75	-56.03
SUM85-05	10672.59	5175.91	5496.67	13691.19	15578.67	-1887.48	3609.19

1) FY 1982 receipts are estimated as if AS43.21 were in effect for the whole year in colusn 2 then as if AS43.20 were in effect for the whole year in colusn 3 though each was in effect only half the fiscal year.

2) FY 1982 collections under SB 524 of $668.9m are comprised of $538.2m from AS43.21"OLD SEPARATE ACCT" law and $130.7 from AS43.20 "CURRENT MODIFIED APPORTIONMENT" law.

3) FY 1985 HB353 Corp. Inc. Tax includes $60.9m of AS43.20 already collected through December 31, 1984.

4) FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.

5) Based on 6/85 70% case price and production assumptions.

TABLE 2a
Calculation of State Petroleum Revenues as a
Percent of Adjusted Production Income
6/85 Forecast Assumptions 70% Case FY 85-05 Using WHV

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3525.22	31.42%
				Pre SB 524	
				Impact SB 524	
82	12958.93	1740.58	11218.35	3525.22	31.42%
83	11941.70	2113.21	9828.49	3270.36	33.27%
84	11327.62	2511.29	8816.33	3148.49	35.71%
85	11382.33	2832.59	8549.74	3161.10	36.97%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	11382.33	2832.59	8549.74	3297.36	38.57%
86	10626.57	3018.24	7608.33	3277.37	43.08%
87	10097.40	3372.15	6725.24	3008.16	44.73%
88	10290.63	3724.11	6566.52	2737.62	41.69%
89	10851.82	4006.66	6845.16	2811.92	41.08%
90	11219.23	4192.75	7026.48	2890.57	41.14%
91	11135.31	4239.84	6895.47	2845.35	41.26%
92	11619.35	4306.37	7312.98	2937.53	40.17%
93	11906.75	4294.64	7612.10	2999.89	39.41%
94	11555.98	4200.03	7355.96	2696.65	39.38%
95	11412.40	4134.28	7278.12	2839.38	39.01%
96	11031.65	4068.39	6963.25	2715.29	38.99%
97	10742.51	3988.64	6753.87	2606.74	38.60%
98	10330.41	3814.79	6515.62	2478.06	38.03%
99	9886.53	3668.77	6217.76	2343.22	37.69%
2000	9386.09	3490.23	5895.86	2196.96	37.26%
01	8490.22	3343.89	5146.33	1936.40	37.63%
02	7572.23	3202.43	4369.80	1665.97	38.12%
03	6788.11	3173.14	3614.98	1430.85	39.58%
04	5928.08	3088.80	2839.28	1190.54	41.93%
05	5324.82	3045.12	2279.70	1009.80	44.30%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	Total Petroleum Production Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	12958.93	1740.58	11218.35	3502.40	31.22%
				AS43.20 & 55	
82	12958.93	1740.58	11218.35	3928.80	35.02%
83	11941.70	2113.21	9828.49	3321.58	33.80%
84	11327.62	2511.29	8816.33	3220.43	36.53%
85	11382.33	2832.59	8549.74	3154.10	36.89%
				AS43.20 & 55	
85	11382.33	2832.59	8549.74	3154.10	36.89%
86	10626.57	3018.24	7608.33	3043.65	40.00%
87	10097.40	3372.15	6725.24	2969.30	44.15%
88	10290.63	3724.11	6566.52	2794.18	42.55%
89	10851.82	4006.66	6845.16	2856.64	41.73%
90	11219.23	4192.75	7026.48	2921.76	41.58%
91	11135.31	4239.84	6895.47	2858.94	41.46%
92	11619.35	4306.37	7312.98	2929.87	40.06%
93	11906.75	4294.64	7612.10	2974.17	39.07%
94	11555.98	4200.03	7355.96	2853.84	38.80%
95	11412.40	4134.28	7278.12	2793.96	38.39%
96	11031.65	4068.39	6963.25	2775.67	39.86%
97	10742.51	3988.64	6753.87	2548.60	37.74%
98	10330.41	3814.79	6515.62	2405.06	36.91%
99	9886.53	3668.77	6217.76	2257.66	36.31%
2000	9386.09	3490.23	5895.86	2103.35	35.68%
01	8490.22	3343.89	5146.33	1652.20	35.99%
02	7572.23	3202.43	4369.80	1602.40	36.67%
03	6788.11	3173.14	3614.98	1390.72	38.47%
04	5928.08	3088.80	2839.28	1182.56	41.65%
05	5324.82	3045.12	2279.70	1027.10	45.05%

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1) FY 1985 HB353 Corp. Inc. Tax includes $60.8m of AS43.20 already collected through December 31, 1984 and half a year of the new tax.

2) Based on 6/85 70% case price and production assumptions.

TABLE 2b
Calculation of State Petroleum Revenues as a
and as a Percent of Prod'n & Pipeline Income
6/85 Forecast Assumptions 70% Case FY 85-05 Using WHV

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3896.85	28.62%
				Pre SB 524	
				Impact SB 524	
82	16455.80	2839.52	13616.28	3896.85	28.62%
83	15469.75	3156.70	12313.06	3644.37	29.60%
84	14955.03	3492.67	11462.37	3544.02	30.92%
85	15135.98	3750.89	11385.10	3569.86	31.36%
				HB 353 as of 1/1/85 1)	
				Impact HB 353	
85	15135.98	3750.89	11385.10	3585.00	31.49%
86	14387.36	3907.71	10479.66	3687.41	35.19%
87	13930.61	4255.05	9675.56	3418.97	35.34%
88	14021.78	4590.92	9430.87	3138.59	33.28%
89	14534.91	4861.97	9672.95	3202.64	33.11%
90	14762.89	5041.00	9721.89	3265.45	33.59%
91	14396.60	5079.20	9317.41	3192.20	34.26%
92	14737.37	5132.85	9604.52	3263.10	33.97%
93	14836.00	5106.76	9729.24	3304.47	33.96%
94	14159.38	4997.89	9161.50	3169.51	34.60%
95	13768.29	4922.30	8846.00	3082.52	34.85%
96	13116.52	4847.39	8269.13	2928.73	35.42%
97	12584.20	4758.72	7825.49	2791.86	35.68%
98	11935.47	4573.61	7361.86	2636.14	35.81%
99	11277.87	4418.18	6859.69	2475.96	36.09%
2000	10584.46	4230.95	6353.52	2306.26	36.30%
01	9464.018	4078.47	5385.55	2020.33	37.51%
02	8342.030	3937.21	4404.82	1724.72	39.16%
03	7399.393	3914.46	3484.94	1467.52	42.11%
04	6391.219	3837.70	2553.52	1206.71	47.26%
05	5683.562	3806.07	1877.49	1008.45	53.71%

With AS 43.20 Corporate Income Tax & AS 43.55 Production Tax

Fiscal Year	-----Total Petroleum----- Gross Revenue	Cost Deductns	Net Revenue	State Petrol Revenues	State / Net Rev %
82	16455.80	2839.52	13616.28	3664.40	26.91%
				AS43.20 & 55	
82	16455.80	2839.52	13616.28	4090.80	30.04%
83	15469.75	3156.70	12313.06	3478.98	28.25%
84	14955.04	3492.67	11462.37	3386.43	29.54%
85	15135.99	3750.89	11385.10	3316.10	29.13%
				AS43.20 & 55	
85	15135.98	3750.89	11385.10	3316.10	29.13%
86	14387.36	3907.71	10479.66	3199.42	30.53%
87	13930.61	4255.05	9675.56	3118.84	32.23%
88	14021.78	4590.92	9430.87	2937.49	31.15%
89	14534.91	4861.97	9672.95	2993.72	30.95%
90	14762.89	5041.00	9721.89	3052.61	31.40%
91	14396.60	5079.20	9317.41	2983.56	32.02%
92	14737.37	5132.85	9604.52	3048.25	31.74%
93	14836.00	5106.76	9729.24	3086.32	31.72%
94	14159.38	4997.89	9161.50	2959.76	32.31%
95	13768.29	4922.30	8846.00	2893.65	32.71%
96	13116.52	4847.39	8269.13	2859.13	34.70%
97	12584.20	4758.72	7825.49	2635.83	33.68%
98	11935.47	4573.61	7361.86	2486.06	33.77%
99	11277.87	4418.18	6859.69	2332.43	34.00%
2000	10584.46	4230.95	6353.52	2171.89	34.18%
01	9464.018	4078.47	5385.55	1914.51	35.55%
02	8342.030	3937.21	4404.82	1658.48	37.65%
03	7399.393	3914.46	3484.94	1440.57	41.34%
04	6391.219	3837.70	2553.52	1226.18	48.02%
05	5683.562	3806.07	1877.49	1064.48	56.70%

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1) FY 1985 HB353 Corp. Inc Tax includes $60.8m of AS43.20 already collected through December 1, 1984 and half a year of the new tax.

2) Based on 6/85 70% case price and production assumpuions.

TABLE 3
Pipeline, Production & Exploration
Income Tax Estimates
(mil current FY $)

Fiscal Year	Total Revenue	State Royalty Share	Prod'n Cons Tax	Total Property Tax	Total Oper'g Costs	Total Depre	Total Acquis Costs	Windfall Profits Tax	Interest Expense Uncap	Exploratn Costs	Admin Costs	Other Deductns	Total Deductns	Total Net Income	Liability HB 353 1)	Collections HB 353 1)	Collections AS 43.20 2)	Diff
82	15455.80	1564.30	1219.03	275.90	939.80	602.58	0.77	2017.66	720.69	190.90	236.20	148.58	7916.41	8539.40	802.70	837.62	130.72	706.90
83	15469.75	1442.73	1098.94	306.55	1100.56	780.16	0.98	1018.38	676.04	204.26	252.30	142.39	7023.30	8446.46	793.97	796.15	236.00	560.15
84	14955.04	1370.57	1032.93	357.66	1259.34	998.45	1.09	412.33	614.13	218.56	264.90	136.20	6666.16	8288.87	779.15	782.86	265.10	517.76
85	15135.99	1362.44	1013.86	396.56	1449.17	1093.32	0.80	70.26	565.55	233.86	278.20	130.00	6594.01	8541.97	802.95	797.00	168.60	628.40
85	15135.99	1362.44	1377.52	396.56	1449.17	1093.32	0.80	69.59	565.55	233.86	278.20	130.00	6887.41	8248.58	775.37	581.52	168.60	412.92
86	14387.37	1281.15	1262.27	420.27	1477.66	1224.05	0.76	46.77	541.76	247.56	292.10	123.82	6871.40	7515.97	706.50	723.72	235.73	487.99
87	13930.62	1212.62	1076.73	465.05	1600.34	1442.16	8.29	29.02	517.87	262.07	306.70	117.63	7009.45	6921.16	650.59	664.57	260.61	403.96
88	14021.79	1178.25	785.41	522.69	1735.17	1619.02	32.60	20.35	490.28	277.42	322.00	114.43	7077.27	6944.52	652.78	652.24	286.69	365.54
89	14534.92	1214.68	778.54	543.09	1796.67	[illegible].55	71.31	17.39	466.41	293.68	338.10	105.24	7398.28	7136.64	670.84	666.33	305.76	360.57
90	14762.89	1259.40	784.53	551.39	1854.43	[illegible].31	117.68	16.27	442.64	310.89	355.00	99.05	7636.32	7126.57	669.90	670.13	314.61	355.52
91	14396.61	1251.54	749.98	545.92	1855.24	1859.87	150.78	14.42	418.55	329.10	372.80	92.86	7626.64	6769.97	636.38	644.76	313.14	331.61
92	14737.37	1305.68	768.16	536.92	1880.35	1880.23	152.28	9.36	393.54	348.38	391.40	86.67	7743.81	6993.56	657.39	652.14	311.00	341.14
93	14836.01	1343.04	772.90	524.41	1801.28	1846.17	151.20	3.87	367.83	368.60	411.00	80.48	7747.11	7088.89	666.36	664.12	306.83	357.28
94	14159.38	1307.55	718.76	509.50	1846.56	1764.64	145.28	0.14	345.21	390.40	431.50	74.29	7533.70	6625.69	622.81	633.70	298.04	335.66
95	13768.30	1294.13	691.55	492.18	1794.52	1721.36	142.96	0.00	328.97	413.28	453.10	68.10	7400.16	6368.14	598.61	604.66	287.54	317.12
96	13116.53	1255.86	636.25	470.56	1762.00	1665.21	128.63	0.00	316.45	437.49	475.70	61.91	7210.06	5906.46	555.21	566.06	298.04	268.02
97	12564.21	1226.77	588.58	445.39	1736.20	1590.25	110.30	0.00	[illegible]4.62	463.13	499.50	55.72	7019.46	5564.75	523.09	531.12	263.02	268.09
98	11935.47	1182.46	535.28	419.28	1701.13	1425.06	90.11	0.00	293.02	490.26	524.50	49.53	6710.63	5224.84	491.14	499.12	249.03	250.09
99	11277.87	1136.99	481.42	392.96	1672.97	1271.87	77.2.	0.00	283.10	518.99	550.70	43.34	6429.55	4848.32	455.74	464.59	234.66	229.93
2000	10584.47	1085.01	426.21	365.49	1609.52	1120.11	62.59	0.00	273.89	549.40	578.30	37.14	6107.66	4476.81	420.82	429.55	219.24	210.31
01	9464.02	984.97	354.12	312.81	1574.08	962.54	51.13	0.00	265.99	581.59	607.20	30.95	5730.37	3733.65	350.96	368.43	201.62	166.81
02	8342.03	881.27	285.39	260.39	1541.87	813.50	41.00	0.00	262.91	615.66	637.50	24.76	5364.26	2977.77	279.91	297.67	183.82	113.85
03	7399.39	793.12	237.25	208.85	1539.02	708.25	34.14	0.00	263.33	651.74	699.40	18.57	5153.68	2245.72	211.10	228.30	167.72	60.58
04	6591.22	694.26	195.90	157.62	1538.45	605.57	24.04	0.00	264.44	689.92	702.90	12.38	4885.48	1505.74	141.54	158.93	152.99	5.94
05	5683.56	624.48	173.46	106.53	1518.24	530.99	17.43	0.00	264.88	730.35	738.00	6.19	4710.54	973.02	91.46	103.98	139.26	-35.28

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1) These estimates assume the tax plan is in effect for the whole year; for FY 1982-85 this is Pre SB 524, for FY 1985-05 this is HB 353.

2) FY82 collections of $130.72m are the actual amounts collected or credited to CY82 liability. The estimate for a full year under AS43.20 in FY82 is $242.5m which would result in a difference of $595.12m as presented in column 4 of Table 1. FY 1985 AS43.20 collections are expected to be low due to substantial refunds and credits for prior year's tax overpayments. Tax liability on a calendar year basis under AS43.20 was CY82, $236.50m; CY83, $224.01m; CY84 $241.54m.

3) Based on 6/85 70% crude price and production assumptions.

TABLE 4
All Producing Fields
Income Tax Estimates
(mil current FY $)

Fiscal Year	Oil Prod'n (mil B/D)	Wellhead Value 1) (cur $)	Gas Prod'n (mcf/day)	Gas Price ($/mcf)	Total Revenue (cur $)	State Royalty Share	Prod'n Cons Tax	Property Tax	Total Oper'tg Costs	Depre Devel Costs	Amort of Acquis Costs	Windfall Profits Tax	Interest Expense	Explorato Costs (expend)	Admin Cost	Other Deductns	Total Deductns	Total Taxable Income	Total Tax Liability	Total Tax Collectns
82	1.6523	21.293	507000	0.590	12958.93	1564.30	1219.03	113.90	710.80	333.93	0.77	2017.66	119.40	190.90	236.20	148.58	6655.47	6303.46	592.53	627.99
83	1.7006	19.040	503000	0.670	11941.70	1442.73	1090.94	149.15	880.56	511.51	0.98	1018.38	121.20	204.26	252.30	142.39	5822.41	6119.30	575.21	579.54
84	1.7183	17.864	505030	0.670	11327.62	1370.57	1032.93	191.66	1038.34	729.80	1.09	412.33	122.40	218.56	264.90	136.20	5518.78	5808.83	546.03	553.33
85	1.7523	17.463	565091	0.971	11382.33	1362.44	1013.86	234.56	1237.67	824.67	0.80	70.26	127.40	233.86	278.20	130.00	5513.71	5868.61	551.65	550.24
85	1.7523	17.483	565091	0.971	11382.33	1362.44	1377.52	234.56	1237.67	824.67	0.80	69.59	127.40	233.86	278.29	130.00	5807.11	5575.22	524.07	393.05
86	1.7528	16.273	537624	1.097	10626.57	1281.15	1262.27	284.50	1266.70	955.40	0.76	46.77	131.90	247.56	292.10	123.82	5826.16	4800.41	451.24	469.45
87	1.7819	15.105	625000	1.200	10097.40	1212.62	1076.73	315.51	1367.96	1173.51	8.29	29.02	136.10	262.07	306.70	117.63	5977.01	4120.38	387.32	403.30
88	1.7312	15.753	705650	1.306	10290.63	1178.25	765.41	379.38	1468.69	1350.37	32.60	20.25	138.60	277.42	322.00	114.43	6067.15	4223.48	397.01	394.58
89	1.7058	16.843	714549	1.400	10851.82	1218.68	778.54	406.01	1537.02	1521.90	71.31	17.39	139.10	293.68	338.10	105.24	6405.89	4445.93	417.92	412.69
90	1.6392	17.987	797800	1.570	11219.23	1259.40	784.53	420.54	1577.17	1592.66	117.68	16.27	140.30	310.89	355.00	99.05	6657.22	4562.01	428.83	426.10
91	1.5977	19.262	858950	1.705	11135.31	1251.54	749.98	421.30	1562.18	1591.22	150.78	14.42	140.90	329.10	372.80	92.86	6662.66	4472.65	420.43	422.53
92	1.4999	20.945	902485	1.856	11619.35	1305.88	768.16	418.54	1574.96	1611.58	152.28	9.36	141.10	348.38	391.40	86.67	6798.95	4820.40	453.12	444.95
93	1.3515	22.778	920067	1.995	11906.75	1343.04	772.90	412.26	1584.34	1577.52	151.20	3.87	141.20	368.80	411.00	80.48	6822.61	5083.90	477.89	471.69
94	1.2011	24.762	893060	2.149	11555.98	1307.55	718.76	403.58	1521.36	1495.99	145.28	0.14	141.20	390.40	431.50	74.29	6629.92	4926.07	463.05	466.76
95	1.0876	26.856	906549	2.270	11412.40	1294.13	691.55	392.49	1461.42	1452.71	142.96	0.00	142.70	413.28	453.10	68.10	6512.45	4899.95	460.60	461.21
96	0.9635	29.080	920462	2.395	11031.65	1255.86	636.25	377.10	1421.40	1396.56	128.63	0.00	146.70	437.49	475.70	61.91	6337.60	4694.04	441.24	446.68
97	0.8521	31.723	936358	2.562	10742.51	1226.77	588.58	358.16	1386.89	1321.60	110.30	0.00	151.50	463.13	499.50	55.72	6162.15	4580.36	430.55	433.23
98	0.7436	34.548	954349	2.737	10330.41	1182.46	535.28	338.28	1347.18	1156.41	96.11	0.00	156.80	490.26	524.50	49.53	5870.81	4459.60	419.20	422.94
99	0.6457	37.580	943764	2.987	9886.53	1136.99	481.42	318.19	1313.11	1003.22	77.21	0.00	162.20	518.99	550.70	43.34	5605.37	4281.16	402.43	406.62
2000	0.5564	40.823	924739	3.244	9386.09	1085.01	426.21	296.95	1243.34	851.46	62.59	0.00	168.00	549.40	578.30	37.14	5298.40	4087.69	384.24	389.79
01	0.4928	44.381	890963	3.550	8490.22	984.97	354.12	250.50	1205.14	693.89	51.13	0.00	174.60	581.59	607.20	30.95	4933.48	3556.74	334.33	346.81
02	0.3587	48.191	899667	3.847	7572.23	881.27	285.39	204.31	1158.25	544.85	41.00	0.00	180.40	615.66	637.50	24.76	4573.40	2998.83	281.89	295.00
03	0.2855	52.293	879601	4.172	6788.11	793.12	237.25	159.00	1142.58	439.60	34.14	0.00	187.10	651.74	699.40	18.57	4362.51	2425.61	228.01	241.48
04	0.2171	56.904	860541	4.518	5928.48	694.26	195.90	114.00	1128.64	336.92	24.04	0.00	194.00	689.52	702.90	12.38	4092.96	1835.12	172.50	186.38
05	0.1688	61.951	843787	4.896	5324.82	624.48	173.46	89.15	1059.42	262.34	17.43	0.00	201.40	730.35	738.00	6.19	3912.21	1412.61	132.79	142.71

1) These prices are weighted average wellhead values derived from the various values at the N. Slope and Cook Inlet fields evaluated in this study.

TABLE 5
Trans Alaska Pipeline
Income Tax Estimates
(all current FY $)

Fiscal Year	Pipeline Thruput (all B/D)	Tariff ($/B)	Total Revenue	Operat'g Costs/ Year	Amort & Deprec	Uncap Interest	Property Tax	Total Deduction	Net Income	Tax Liability (9.4%)
82	1.5680	6.11	3496.88	229.00	268.65	601.29	162.00	1260.94	2235.94	210.18
83	1.5300	5.93	3528.05	220.00	268.65	554.84	157.40	1200.89	2327.16	218.75
84	1.6536	6.01	3627.42	221.00	268.65	491.73	166.00	1147.38	2480.04	233.12
85	1.7140	6.00	3753.66	211.50	268.65	438.15	162.00	1080.30	2673.36	251.30
86	1.7173	6.00	3760.80	210.96	268.65	409.86	155.77	1045.24	2715.56	255.26
87	1.7503	6.00	3833.22	232.48	268.65	381.77	149.54	1032.44	2800.78	263.27
88	1.7037	6.00	3731.16	246.48	268.65	351.68	143.31	1010.12	2721.04	255.78
89	1.4818	6.00	3683.10	259.65	268.65	327.01	137.08	992.39	2690.71	252.93
90	1.6181	6.00	3543.66	277.26	268.65	302.34	130.85	979.10	2564.56	241.07
91	1.4892	6.00	3261.30	293.06	268.65	277.65	124.62	963.98	2297.32	215.95
92	1.4238	6.00	3118.02	305.39	268.65	252.44	118.38	944.86	2173.16	204.28
93	1.3376	6.00	2929.26	316.94	268.65	226.53	112.15	924.27	2004.99	188.47
94	1.1808	6.00	2603.40	325.20	268.65	204.01	105.92	903.78	1699.62	159.76
95	1.0758	6.00	2355.90	333.10	268.65	186.27	99.69	887.71	1468.19	138.01
96	0.9520	6.00	2084.88	340.60	268.65	169.75	93.46	872.46	1212.42	113.97
97	0.8410	6.00	1841.70	348.31	268.65	153.12	87.23	857.31	984.39	92.53
98	0.7329	6.00	1605.06	353.95	268.65	136.22	81.00	839.82	765.24	71.93
99	0.6353	6.00	1391.34	359.86	268.65	120.90	74.77	824.18	567.16	53.31
2000	0.5472	6.00	1198.38	366.18	268.65	105.89	68.54	809.26	389.12	36.58
01	0.4447	6.00	973.80	373.94	268.65	91.99	62.31	796.89	176.91	16.63
02	0.3515	6.00	769.80	383.62	268.65	82.51	56.08	790.86	-21.06	-1.98
03	0.2791	6.00	611.28	396.44	268.65	76.23	49.85	791.17	-179.89	-16.91
04	0.2115	6.00	463.14	409.81	268.65	70.44	43.62	792.52	-329.38	-30.96
05	0.1638	6.00	358.74	428.82	268.65	63.48	37.38	798.33	-439.59	-41.32

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1) No gas production considered (26 TCF).
2) No TAPS settlement.
3) Some account of total crude taken off at N. Pole i.e. does not go to Valdez.
4) Based on 6/85 70% case price and production assumptions.
5) Seal Is. excluded.

ASSUMPTIONS:

Property taxes per AS43.56 @2% gross.

TABLE 6
WINDFALL PROFITS TAX DEDUCTION
(mil current FY $)

DEDUCTION FROM FY TAXABLE INCOME

Fiscal Year	Sadlerochit	Cook Inlet	Total	Impact on FY Tax Liability (Total * .094)
Under Pre-SB 524				
	a)			
82	1750.61	267.05	2017.66	189.66
83	848.78	169.60	1018.38	95.73
84	289.25	123.08	412.33	38.76
85	8.93	61.33	70.26	6.60
Under HB 353				
	b)			
85	8.51	61.09	69.60	6.54
86	-0-	46.77	46.77	4.40
87	-0-	29.02	29.02	2.73
88	-0-	20.35	20.35	1.91
89	-0-	17.39	17.39	1.63
90	-0-	16.27	16.27	1.53
91	-0-	14.42	14.42	1.36
92	-0-	9.36	9.36	.88
93	-0-	3.87	3.87	.36
94	-0-	.14	.14	.01

Note:

1/ Based on 6/85 70% case price and production assumptions.

2/ Windfall Profits Tax is phased out and no longer in effect in FY 1995 and thereafter.

3/ The reason for the slight difference in FY 85 under Pre-SB 524 compared to HB 353 is the difference in the Oil Severance Tax law and thus, the severance tax adjustment under the WPT.

a) For FY 1982 through 1985, these impacts are includ d in Tables 3 and 4 under the Pre-SB 524 separate accounting corporate tax. If the WPT was not a deduction for those years, the total tax liability columns would have been increased by these amounts.

b) For FY 1982 through 2005, these impacts are not included in Tables 3 and 4 under the HB 353 separate accounting corporate tax. If the WPT was a deduction for these years, the total tax liability columns would be reduced by these amounts. In FY 1985, the reduction would be approximately one half the amount because HB 353 goes into effect midway through the fiscal year.

V.

This section will present comments and conclusions relative to HB 353 based on the analysis outlined and summarized in preceding sections.

As to the feasibility analysis performed relative to the impact of HB 353 on development and production of the "marginal" North Slope fields, the following qualifications should be noted:

The feasibility analysis performed in the Petroleum Revenue Forecasting Model tests the real after tax discounted cash flow rate of return from a field against an assumed "hurdle" real rate of return to determine feasibility. If the rate of return for the field given projected production, prices, development costs, operating costs and tax rates exceeds the hurdle rate, development of the field is deemed feasible.

There are three potential problems with applying this quantitative analysis to the "marginal" North Slope fields and then drawing conclusions about the actual timing and magnitude of their development. The first is the "hurdle" rate used in the model may not be the same as the "hurdle" rate actually used by the corporations with lease rights to develop the field. The second is that the model analysis assumes no capital budget constraint. In reality, the corporations have a limited amount of capital to invest in the development of fields in Alaska and

elsewhere in the world. Even though development of a field in Alaska may be projected by the corporation to provide an acceptable rate of return given the corporation's actual "hurdle" rate, there may be other even more attractive projects elsewhere which would be developed instead, given a limited capital budget. Finally, there may be non-quantifiable judgmental factors which the corporations consider in making their investment decisions. These types of judgmental considerations are necessary to distinguish between two investment alternatives which are projected to be equally attractive on a quantitative basis.

Regardless of these three potential problems in applying the feasibility model to analyze when and at what level a field will actually be developed, the model is useful in analyzing the relative effect of alternative tax structures on rates of return and feasibility of development given projected production, costs and prices. Here, as discussed earlier, our analysis indicated the impact of the HB 353 tax structure with respect to Petroleum Corporate Income Tax and Petroleum Severance Tax on the feasibility of development was relatively insignificant. The future of oil prices will have a much more significant effect on the feasibility of development for these fields.

As to the revenue impact of HB 353, the analysis indicated that under all alternative price and production scenarios examined, cumulative revenues from income and severance taxes for FY 1985 through FY 2005 were greater under HB 353 than under the current tax structure. The absolute and percentage gain, however, varied significantly between scenarios.

For example, cumulative revenues from income and severance taxes for FY 1985 through FY 2005 were 12.12 percent higher under HB 353 than under current law given the Mean case price and production scenario, 8.38 percent higher given the 30 percent scenario and 17.39 percent higher given the 70 percent scenario.

This is because the tax structure proposed by HB 353 is more sensitive to price and production changes than the current tax structure. The severance tax under HB 353 is slightly less sensitive to price and production changes than the current severance tax simply because it is levied at a lower maximum rate, 12.25 percent as compared to 15 percent under the current law. However, this is more than offset by the income tax which is significantly more sensitive under HB 353 than under current law resulting in greater overall revenue sensitivity under HB 353.

The cumulative revenues collected from income taxes for FY 1985 through FY 2005 under the current apportionment tax structure were projected to be 5.04 percent lower given the 30 percent scenario as compared to the Mean scenario and 16.94 percent higher given the 70 percent scenario as compared to the Mean scenario. The cumulative revenues collected under the proposed HB 353 separate accounting income tax were projected to be 14.52 percent lower given the 30 percent scenario compared to the Mean scenario and 30.83 percent higher given the 70 percent scenario compared to the Mean scenario. The reason for this

is under separate accounting, revenue collections are directly dependent upon the level of production and wellhead values in Alaska. Under apportionment, however, revenue collections are dependent on both worldwide income and the level of Alaska activity compared to worldwide activity as measured by apportionment factors. Therefore, the apportionment tax structure is less directly sensitive to changes in Alaska production and wellhead values. Also, it should be noted that a given percentage change in worldwide oil prices results in a greater percentage change in Alaska wellhead values due to the fixed transportation cost differential which exists between the two. For example, if world crude prices were $20.00 per barrel and there was a total fixed transportation cost of $10.00 per barrel to get Alaska crude to market, the wellhead value of Alaska crude would be $10.00 per barrel. If world prices were to increase by 5 percent to $21.00 per barrel, Alaska wellhead value would increase from $10.00 to $11.00 per barrel which would represent a 10 percent increase. Therefore, alternative price scenarios result in greater percentage differences in Alaska activity and income upon which separate accounting is based than in worldwide activity and income upon which apportionment is based.

The HB 353 proposal, because it is more sensitive to oil prices, has the potential for greater upside gain should prices increase and the potential for greater downside risk should prices decrease when compared to the current tax structure.

It should be noted that by FY 2005, the revenues collected under apportionment were projected to be greater than under separate accounting given all alternative scenarios. This is because under apportionment, worldwide income was assumed to increase over time and was only partially offset by declining apportionment factors as Alaska activity declined. Under separate accounting, collections declined directly over time with declining Alaska activity and income.

It is also interesting to note that by FY 2005, collections under the current apportionment tax are approximately equal given both the Mean and 70 percent assumptions. This is because even though the 70 percent case assumes a higher long-run worldwide apportionable income growth rate it also assumes a higher growth rate in worldwide production which acts to reduce the apportionment factor at a faster rate thus offsetting the higher income growth rate. As noted earlier, however, over the entire period from FY 1985 through FY 2005, the 70 percent case assumptions resulted in revenue collections which were 16.94 percent higher than the Mean.

In comparing revenue collections under separate accounting in FY 2005 given Mean and 70 percent scenario assumptions, the 70 percent case generates less revenue than the Mean case. The reason for this is that under the 70 percent scenario, development of fields in Alaska occurs earlier and at a more rapid pace. Therefore, by FY 2005, production

under the 70 percent scenario is less than production under the Mean scenario. As noted earlier, however, over the entire period from FY 1985 through FY 2005, the 70 percent case assumptions resulted in revenue collections which were 30.83 percent higher than the Mean.

A number of revisions have been made to the analysis compared with the preliminary analysis previously presented to the Legislature during the 1985 legislative session. The previous analysis was based on March, 1985 Mean case price assumptions whereas this analysis is based on June, 1985 price assumptions which are significantly lower in the Mean case. This analysis includes two additional marginal fields, West Sak and Point Thompson which were not included before. The March analysis included projections only through FY 1995. Total projected cumulative revenue collections from both income and severance taxes given Mean case assumptions under both current and proposed tax structures are lower now than in March.

Severance taxes projected under both laws are lower due to lower price and wellhead value projections in spite of somewhat higher production from the inclusion of the two additional fields in the analysis.

Income tax projections under the current apportionment law are lower due primarily to lower expectations for long-run worldwide apportionable income growth rates. Income tax projections under the proposed HB 353 separate accounting law are lower due to lower wellhead

values and hence, gross revenues. The inclusion of additional fields does not result in enough additional production to offset the effect of lower wellhead values on gross revenues, and the additional fields included also had deductions associated with them which reduced net taxable income even more. Also, as discussed earlier, separate accounting deductions primarily operating cost estimates, have been revised upward since March.

The revisions since March have resulted in a greater downward revision in projected collections under the current income and severance tax laws than under the proposed HB 353 income and severance tax laws. Therefore, the absolute and percentage revenue gain from HB 353 is projected to be greater now than in March. Total cumulative revenues collected for FY 1985 through FY 1995 were projected to be 13.46 percent higher under HB 353 than under current law given the Mean case assumptions in March and now are projected to be 16.79 percent higher for the same period (1985-1995) given the Mean case assumptions.

It should also be noted that due to the revision in the operating cost deduction, the estimates of revenues which would have been collected under the pre-SB 524 separate accounting corporate tax for FY 1982 through FY 1985 are lower now than in March.

376-3111 home

Bill + Mike Kozowski:

Bill has done DNR's rsv estimates -

wd need a thorough analysis to see if drilling is legitimate -

plan of dev't req's dev't of ent area - West End Gileen e.g. -
(like the lease) - they are ^now being diligent in dev't, partly -

you don't mk. rsvs - you borrow

Chat

Sam's group as lessor + unit signator gets a plan of dev't w/ annual oper'g plan updates.

reservoir study - Van Poolen - approp'n in '78 - initially in 72 w/ a 2-dimensional model - cost about $800k - kept Van Poolen on for updates till Dec 84 - state library shd hv copies - legislative library -

don't see any need to update the study - will need it [illegible] is dev'd -

exp'd declined in 2/3d qtr of '89 -

87 decline did not occur bec. no gas sales - no rdxn of pressure ~~[illegible]~~ 26'3

'90 decline will be steeper bec. of ~~[illegible]~~ delayed decline -

160 → 80-acre spacing -

---

changing the shape of the curve vs. the area under it -
is the ELF causing ~~new~~ prodn of add'l volume or just expedited recov'y?

3/22 Kotowski

1) every yr. a progress report or plan of dev't or dev't of acreage - what they did to satisfy prior plan, then propose work for up coming yr - # wells + other facilities

2) Kuparuk + Prudhoe plans hv been pretty lengthy -

3) maximizing recovery - AOGCC is more attuned - thru. model controls - computer models match performance - same projects of proden rates etc. (AOGCC) - drilling permits e proden history / monitoring of pressure / more tech'l on reservoir -

4) DNR > conc'd w/ maxg recy - what are lessees doing to define the reservoir - "optimizing proden" - (inst.)

V w/ Bill -

3/23 who regulates proden rates? AOGCC/DNR both hv regs -

DNR - AS 38.05.180 (q)

AOGCC - AS 31.05.030 (e)(6)

Prudhoe P.O.D

2 diff plans

1) spec. reservoirs - exh. (e) for unit agmt

perm - Triassic Eileen, Sag, Shublik, Sadlerochit

2) p.o.d for lands outside initial participating area -

Lisburne / Kuparuk (part) etc.

"funky"

since approval of unit agmt of p.o.d / perm - Triassic -

Mike hasn't read yet - pretty broad this -

so just get prog reports for. opers for past yr

Kotowski (2)

June 1 86 - May 31 87 - last one filed - shd get a new one by 6/1/88 - They file by 6/1/88 - so we don't know what they've done since ELF took effect for Prudhoe -

dev't plans + rig schedules are avail. fr. companies have POD fr. Osborne -

9 pages for 86-87 -

get back to 1980 -

plan of dev't for unit agmt - 11 pages -

prices / drilling effect on fluid recov / waterflood + drilling to optimize oil -

ELF effect "icing" on the cake -

prob'y hasn't expanded drilling much fr. what wd be expd w/ these prices for oil -

[waterflood modelling - are you using oil beh? do you need to change spacing of wells?

Δ well permitting chart

(3)

Littleton, CO.

Van Poolen - companies do their own modelling =

3/23 Chat re well pmts 279-1433

how long ahead of time -
usu a week to 10 days -
statute says deliver quickly -
AS 31.05.090 - form provided by

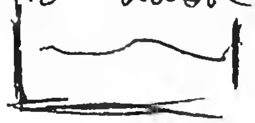
consvn orders - 280 since st'hd -

What does OGCC look at in pmts?
contrary to law reg or order by OGCC
comply w/ pool rules - via public hrg. -

pool rules - well-spacing - etc - so indiv. pmts shd comport w/ rules -

pmt stats - bulletins - monthly - The State

want max that tech'y permits -
offtake limits -
well-spacing -
maximizing ult. recov'y.
safety as it relates to waste only -



Prudhoe - 80
↓
145

Kuparuk - one
Lisburne -
Endicott -

→ Petroleum Info Svc - drill rigs -

Chart-2

1 [now] vs 2 [rigs] @ Kuparuk - ARCO --
SOHIO kept 2 rigs in West end +2 in Endicott
1 in Lisburne from 2

Δ is hist'ly low now

there has not bn much Δ in drilling in
the past year.

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 Porcupine Drive
Anchorage, Alaska 99501

Re: THE REQUEST OF SOHIO ALASKA PETROLEUM COMPANY to present testimony to determine pool rules for the Endicott Oil Pool.	Conservation Order No. 202 Endicott Field Endicott Oil Pool September 20, 1984

IT APPEARING THAT:

1. Sohio Alaska Petroleum Company requested the Alaska Oil and Gas Conservation Commission to hold a public hearing in order to receive testimony for the establishment of pool rules for the development and exploitation of the Endicott Oil Pool.

2. Notice of the public hearing was published in the Anchorage Times on July 24, 1984 and in the Anchorage Daily News on July 25, 1984.

3. A public hearing was held in the Municipality of Anchorage Assembly Room, 3500 East Tudor Road, Anchorage, Alaska on August 22, 1984.

4. Members of the staff of Sohio Alaska Petroleum Company presented testimony and the hearing record was closed at the end of the public hearing.

FINDINGS:

1. Hydrocarbons are trapped in the Kekiktuk Formation, a part of the Endicott Group.

2. There has been widespread usage of "Endicott" as the field name and the field and pool should be named Endicott Field and the Endicott Oil Pool.

3. The vertical limits of the pool may be defined by the accumulations in the Sohio Alaska Petroleum Company Sag Delta No. 4 well which appears to be a typical and representative well.

4. Well control and structural interpretation are adequate to reasonably define the areal limits of the accumulation

5. The pool is bounded by several major faults and there appear to be numerous minor faults within the field limits.

6. The areal extent of the hydrocarbon-bearing reservoir is about 8600 acres.

7. A gas-oil contact has been determined to be a planar horizontal surface fieldwide at 9855 feet subsea.

8. The oil-water contact is assumed to be a planar horizontal surface fieldwide at 10,192 feet subsea.

9. A spacing pattern denser than one well per 160 acres may be necessary to recover the maximum amount of oil.

10. The field is characterized by faulted structural patterns, inconsistent lithology and changing lateral and vertical reservoir characteristics.

11. To adequately evaluate the effectiveness of the reservoir depletion plan, the reservoir pressure, the gas-oil ratio, the gas-oil contact, and the productivity profile of wells should be monitored on a regular and continuous basis soon after regular production commences.

12. Enhanced recovery methods must be employed to achieve maximum recovery. Studies have indicated that a full field waterflood project started within two years after initial production will greatly increase recovery and will not preclude other additional enhanced recovery projects in the future.

13. Studies indicate the ultimate recovery from the reservoir is sensitive to the daily offtake rate.

14. All wells will be drilled from man-made gravel islands with a surface grade approximately 22 feet above the original mud line or ocean floor.

15 The contribution of intervals open to the wellbore in each producing well may be determined by running productivity profile surveys.

16. Initial reservoir and bubble point pressures are estimated to average 4840 psig. The reservoir temperature ranges from 200 to 225 degrees Fahrenheit.

17. Studies indicate that all produced gas, excepting volumes used for lease purposes, should be injected into the gas cap to assist in reservoir pressure maintenance.

18. Structural casing set through the island gravel and below the mud line appears necessary to conduct wellbore operations.

19. Conductor casing set and cemented a minimum of 75 feet below the island surface should provide adequate anchorage for a diverter system.

20. The effects of permafrost thaw-subsidence and freeze back loadings can be mitigated by setting and cementing surface casing of sufficient strength at least 500 feet below the base of the permafrost but no more than 2700 feet true vertical depth.

21. Several casing types and grades that are approved for use as surface casing in the Prudhoe Bay Field and the Kuparuk River Field are adequate for this field.

22. Perforation of cemented casing or liners, slotted liners, wire wrapped screen liners, and open hole completions appear to be equally effective completion techniques.

23. Unless the pool is operated under a unit agreement, the pool management program contemplated in the testimony can not be undertaken, without negatively impacting correlative rights.

24. Statewide regulations presently in effect govern field operations except as modified by this conservation order.

NOW, THEREFORE, IT IS ORDERED THAT the rules hereinafter set forth apply to the following described area referred to in this order as the affected area:

UMIAT MERIDIAN

T11N	R16E	Sections 1, 2, and 12.
T11N	R17E	Sections 3, 4, 5, 6, 7, 8, 9, 10, 13, 14, 15, 16, and 17.
T12N	R16E	Sections 25, 26, 27, 34, 35, and 36.

That portion of those lands in the S½ S½, NW¼ of Block 653 lying north of the south boundary of Sections 22, 23, and 24; T12N, R16E, U.M., Alaska (being identical with line 6-7 on Block 653) and those lands in the S½ SW¼ NE¼ of Block 653 lying north of the south boundary of Section 24, T12N, R16E, U.M., Alaska and east of the west boundary of Section 30, T12N, R17E, U.M., Alaska and those lands in the SW¼ SE¼ NE¼ of Block 653 and those lands in the SE¼ of Block 653 lying east of the west boundary of Sections 30 and 31, T12N, R17E, U.M., Alaska and those lands in the SW¼ SW¼ of Block 654 and

those lands in the SW¼ NW¼ SW¼ of Block 654 and those lands in the SW¼ SE¼ SW¼ of Block 654 and those lands in Block 697 lying in T12N, R17E, U.M., Alaska being the northeast portion of Block 697 and those lands in the NW¼ of Block 698 lying north of the south boundary of Sections 31, 32, and 33, T12N, R17E, U.M., Alaska and those lands in NW¼ NW¼ NE¼ of Block 698 lying north of the south boundary of Sections 33 and 34, T12N, R17E, U.M., Alaska which are within the offshore three-mile arc lines and which are all listed as state area on the "Supplemental Official O.C.S. Block Diagram" approved October 19, 1979 and December 9, 1979, respectively.

That portion of those lands in the S½ and S½ N½ of Block 698 lying east of the west boundary of Sections 2 and 11, T11N, R17E, U.M., Alaska (being identical with the line 4-5 Block 698) and lying north of the south boundary of Section 11, T11N, R17E, U.M., Alaska (being identical with line 5-6 in Block 698) and the SW¼ NW¼ of Block 699 and those lands in the SW¼ of Block 699 lying north of the south boundary of Sections 11 and 12, T11N, R17E, U.M., Alaska and those lands in the SW¼ NW¼ SE¼ of Block 699 and those lands in the SW¼ NW¼ SE¼ of Block 699 and those lands in the SW¼ SE¼ of Block 699 lying north of the south boundary of Section 12, T11N, R17E, U.M., Alaska and east of the west boundary of Sections 7 and 18, T11N, R18E, U.M., Alaska which are within the offshore three-mile arc lines and which are all listed as state area on the "Supplemental Official O.C.S. Block Diagram" approved October 4, 1979 and December 9, 1979, respectively.

Rule 1 FIELD AND POOL NAME.

The field is named the Endicott Field. The hydrocarbons contained within the Kekiktuk Formation constitute a reservoir named the Endicott Oil Pool.

Rule 2 POOL DEFINITION.

The Endicott Oil Pool is defined as the accumulations of oil and gas that are common to and which correlate with the accumulations found in the Sohio Alaska Petroleum Company Sag Delta No. 4 well between the measured depths of 11,496 and 12,812 feet.

Rule 3 WELL SPACING.

Nominal 40 acre drilling units are established for the pool within the described area. Each drilling unit shall conform to quarter-quarter governmental sections as projected. No more than one well may be drilled into and produced from each drilling unit. The pool may not be opened in a well closer than a 1000 feet to any well opened to the pool. The pool shall not be opened in any well closer than 500 feet to the exterior boundary of the affected area. The Commission may administratively approve modifications to well spacing when justified.

Rule 4 CASING AND CEMENTING REQUIREMENTS.

a) Structural casing shall be set by driving or jetting to a sufficient depth below the mud line to ensure support of drilling fluid returns to the surface while drilling hole for a conductor string.

b) Conductor casing to provide for proper anchorage shall be set at least 75 feet below the island surface and sufficient cement shall be used to fill the annulus behind the pipe to the island surface. Cement fill shall be verified by observation of cement returns. The cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

c) Surface casing, to provide for proper anchorage, for preventing uncontrolled flow and to protect the well from the effects of permafrost thaw-subsidence or freeze back loadings, shall be set at least 500 measured feet below the base of the permafrost but not below 2700 feet true vertical depth. Sufficient cement shall be used to fill the annulus behind the casing to at least the mud line.

d) Surface casing types and grades approved for use include:

1)	13-3/8 inch,	72 pounds/foot,	L-80 Buttress;
2)	13-3/8 inch,	72 pounds/foot,	N-80 Buttress;
3)	13-3/8 inch,	68 pounds/foot,	MN-80 Buttress;
4)	10-3/4 inch,	45.5 pounds/foot,	K-55 Buttress;
5)	10-3/4 inch,	45.5 pounds/foot,	HF-ERW Arctic Grade, J-55 Buttress;
6)	9-5/8 inch,	36 pounds/foot,	K-55 Buttress;
7)	9-5/8 inch,	40 pounds/foot,	K-55 Buttress;
8)	9-5/8 inch,	36 pounds/foot,	HF-ERW Arctic Grade, J-55 Buttress;
9)	9-5/8 inch,	40 pounds/foot,	HF-ERW Arctic Grade, J-55 Buttress;
10)	9-5/8 inch,	47 pounds/foot,	L-80 Buttress.

e) The Commission may administratively approve additional types and grades of surface casing upon a showing that the proposed casing and connection can withstand the permafrost thaw-subsidence and freeze back loadings which may be experienced. Evidence submitted to the Commission shall include:

1) full scale tension and compression testing; or
2) finite element model studies, or
3) other types of axial strain data acceptable to the Commission.

f) Alternate means for maintaining the integrity of the well from the effects of permafrost thaw-subsidence and freeze back may be administratively approved by the Commission upon application and presentation of data which show the alternatives are appropriate, based upon accepted engineering principles.

Rule 5 COMPLETION PRACTICES

Wells completed for production from the Endicott Pool may utilize casing strings or liners cemented through the productive intervals and perforated, slotted liners, screen wrapped liners or open hole methods, or combination thereof. The Commission may administratively approve alternate completion methods where appropriate.

Rule 6 PRESSURE SURVEYS.

a) Prior to regular production, a pressure survey shall be taken on each well.

b) The datum for all pressure surveys is 10,000 feet subsea.

c) After regular production commences in each governmental section, a pressure survey shall be taken within six months and again within 12 months on at least one well in the section.

d) Within 12 months after regular production from the pool starts, the operator will submit to the Commission for approval a key-well program setting forth the long term pressure monitoring program for the pool.

e) Pressure survey, as used in this rule, means either a static bottomhole pressure survey or a transient pressure survey.

f) Data from all pressure surveys shall be filed with the Commission on Form 10-412 within 45 days after the survey is taken.

g) The Commission, by administrative order, may amend the key well pressure monitoring program if it is found to be inadequate or impractical.

Rule 7 GAS-OIL RATIO TESTS.

a) After regular production from a well has commenced, a gas-oil ratio test will be taken within four months and each six months thereafter.

b) Gas-oil ratio tests shall be a minimum of four hours duration unless otherwise administratively approved by the Commission.

c) Gas-oil ratio tests will be reported on Form 10-409 and submitted within 45 days after the tests are taken.

Rule 8 GAS VENTING OR FLARING.

a) The venting or flaring of gas is prohibited except as may be authorized by the Commission for facility safety, cases of emergency or operational necessity.

b) Infrequent operations where flaring is necessary, such as the initial commissioning of facilities, plant start-ups after maintenance or tie-in shutdowns and other special activities, may be administratively approved by the Commission upon written request.

c) The Commission will administratively set volumes for safety flares upon receipt of a written request and accompanied by adequate data to support the request.

Rule 9 GAS-OIL CONTACT MONITORING.

a) A compensated neutron log shall be run in each well prior to regular production.

b) A compensated neutron log shall be run in one well per governmental section within 12 months after regular production starts.

c) A key-well gas-oil contact monitoring program will be submitted to the Commission for approval within 12 months after regular production from the pool commences and will constitute the long term gas-oil contact monitoring program.

d) Compensated neutron logs will be submitted within 45 days after they are taken.

Rule 10 GAS-OIL RATIO.

a) The gas-oil ratio in a well will have no upper limit if all gas produced from the pool except quantities used in lease operations or administratively approved for other purposes by the Commission, is injected into the Endicott Oil Pool.

Rule 11 PRODUCTIVITY PROFILES.

a) An appropriate log to establish the productivity or injectivity profile of the intervals open to the wellbore will be run in each well within 12 months after regular production or injection commences.

b) A program to monitor well productivity and injectivity will be submitted to the Commission for approval at least three months before water injection begins.

c) Additional productivity surveys may be required by administrative order if underground waste of hydrocarbons appears imminent.

d) Productivity surveys will be submitted to the Commission within 45 days after the date of the survey.

Rule 12 FIELD-WIDE WATERFLOOD PROJECT.

a) A field-wide waterflood project is approved for the pool area.

b) The field waterflood project must be started within two years after regular production from the pool has started.

c) The waterflood plan will be submitted to the Commission at least three months before actual water injection begins.

d) All applications for permits necessary to implement the waterflood project shall be timely submitted for approval.

Rule 13 POOL OFFTAKE RATE.

a) The maximum calendar quarter average offtake rate from the pool is 125,000 barrels of oil per day. Calendar quarter average offtake rate means the daily average rate determined by dividing the total volume of oil produced in a calendar quarter by the number of days in that calendar quarter.

b) The maximum calendar quarter average offtake rate of 125,000 barrels of oil per day may be exceeded for the purpose of making up a shortfall in the allowable volume of oil produced in a previous calendar quarter providing that the offtake rate for any day does not exceed one hundred ten percent (110%) of the calendar quarter average offtake rate.

c) For the purpose of providing for reasonable operating flexibility, the calendar quarter offtake volume may be exceeded. The volume of oil determined by multiplying 125,000 barrels by the number of days in that calendar quarter establishes an allowable calendar quarter offtake volume. A calendar quarter offtake volume may not exceed the allowable calendar quarter offtake volume by more than one percent (1.0%) without prior approval of the Commission. Volumes of oil exceeding the allowable calendar quarter offtake volume shall be zeroed out in the following calendar quarter by producing at rates lower than the maximum calendar quarter average offtake rate until that volume of oil produced in excess of the previous allowable calendar quarter offtake volume is offset. The volume of oil produced in calendar quarters in excess of the allowable calendar quarter average offtake rate for the purpose of recovering a shortfall in an allowable calendar quarter offtake volume as provided for by (b) above is not given consideration when making a determination

for the purpose of this subsection (c).

d) Gas offtake is not permitted because the reservoir depletion program governed by this order requires that produced gas be injected into the Endicott Oil Pool. At anytime, upon proper petition and after public hearing, the Commission will consider the merits of issuing an order establishing a gas offtake rate. That order would provide for appropriate amendments to the pool depletion program governed by this order to ensure that a loss in ultimate recovery will not occur.

Rule 14 UNITIZATION.

a) Oil and gas leases overlying the affected area shall be unitized and a participating area established for the Endicott Pool prior to the commencement of regular production from the pool.

b) Should unitization and the establishment of a participating area not be accomplished prior to regular production from the pool, this order is null and void. Upon petition and after public hearing, the Commission will issue an order setting forth pool rules governing competitive lease production methods that will ensure the protection of correlative rights and the maximum ultimate recovery from the pool or issue an order mandating pool unitization.

DONE at Anchorage, Alaska and dated September 20, 1984.

C. V. Chatterton, Chairman
Alaska Oil and Gas Conservation Commission

ALASKA OIL AND GAS CONSERVATION COMMISSION

Harry W. Kugler, Commissioner
Alaska Oil and Gas Conservation Commission

Lonnie C. Smith, Commissioner
Alaska Oil and Gas Conservation Commission

go0038hLd
Utermohle

A M E N D M E N T

Offered in the HOUSE

By Cotten

TO: CSHB 390 (Finance)

Page 2, line 1, after (a), through line 8:

Delete all material.

Insert "The distribution of the income and realized capital gains of the endowment is subject to AS 37.07. The net annual realized capital gains of the endowment may be equally divided between the income and the principal of the endowment. Upon application of the foundation's board of directors or its authorized representative, after authorization under AS 37.07 the Alaska Permanent Fund Corporation shall pay to the foundation the income appropriated."

SAM
I did this for Cliff - I guess he's thinking now of sending it to the Daily News

N

GETTING ALASKA'S SHARE OF OIL REVENUES

by Cliff Davidson (1)

Alaskans own Prudhoe Bay, the largest and most prolific oil field in U.S. history. We have derived tremendous benefits from its development: the Permanent Fund, our schools, many municipal improvements, and government services for children, the elderly and the disabled.

However, our share of the revenue from this field has recently been reduced, while the major oil companies are increasing their share and proclaiming their profitability in a tough oil market. For this fiscal year, about $185 million has been directly transferred from Alaska to the corporate treasuries of several major international oil companies.

All over the state, people who need school improvements and municipal services are wondering why the Legislature allowed a reduction in oil and gas taxes when our state revenues are in precipitous decline.

The answer to the question is that the Legislature scheduled the tax break back in 1981, when oil prices were rising and it was thought that Prudhoe Bay would be in

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1 - Cliff Davidson represents Kodiak in the State House and is a member of the House Resources Committee.

decline by 1987. Today it is clear that the industry will continue to operate, quite profitably, if the tax regime is restored. Yet the State Senate has refused to act on the oil tax bill, despite Governor Cowper's support for it and the State House's.

Last year the House passed a bill, introduced at the Governor's request, that did two important things:

* prevented large tax breaks for giant oil fields like Prudhoe and Kuparuk, where tax incentives aren't needed, and

* provided a new tax incentive for production from every other known field in Alaska, including marginal fields such as Endicott, Lisburne, and Milne Point, which was shut down in 1987 because it was uneconomic.

This approach makes sense. Forbes magazine recently reported that Atlantic Richfield is one of the most profitable oil companies in the world, and guess where the company gets 67% of its oil? From Kuparuk and Prudhoe Bay. Tax breaks are simply unnecessary for these oil fields.

The chief executive of Atlantic Richfield recently boasted that the company's profits are the "best in the

industry." The company has also publicly reported that it increased its Alaska production while reducing production from other sources. These aren't the actions of a company producing from a marginal property.

Meanwhile, British Petroleum last year completed its acquisition of Standard Oil. Now it owns 100% of that company, which got 98% of its oil production from Alaska. And Kuwait's national oil company has purchased more than 20% of BP. These aren't the actions of corporations worried about the profitability and potential of Alaska oil and gas production.

Some industry representatives claim that the tax break has encouraged more drilling on the North Slope. No proof has been offered that the new drilling provides Alaskans extra jobs or that the long-term production of Prudhoe and Kuparuk is being increased. Instead, we might just be seeing the hastier depletion of oil and gas reserves.

Industry representatives also talk about "tax stability." They imply that there was a compact between the 1981 Legislature and the oil and gas industry to install a tax break in 1987. But they neglect to mention that there were other issues -- legislative instability, legal battles, and inaccurate production projections -- that influenced the

1981 Legislature. They also don't seem to realize that today's legislators need to deal with today's problems.

In fact, it's clear that the industry actually supports tax changes when those changes benefit the industry. In 1981 the industry came to the Legislature (in a time of oil price inflation) and asked for tax breaks. The Legislature responded by instituting a new "unitary" tax system. Since that time, Alaskans have foregone billions of dollars worth of revenue that would have been collected under the former system.

are we sure of this?

Alaskans have a choice here: shall we continue to forfeit tax revenues that could be put to many purposes around the state, or shall we go ahead and collect taxes that won't harm the industry and will bring us back to where we stood a year ago? I'm strongly supportive of Governor Cowper's effort to rescind the oil tax break, and I'm glad that the House and the Governor are working together on a tax system that will truly serve the interests of all Alaska.

How does the 1987 oil tax break affect Alaskans?

* It has reduced state revenues by about $185 million this fiscal year. This money goes directly to the corporate treasuries of major oil companies.

* It will cost about $1.2 billion over five years.

What is wrong with the 1987 tax break?

* It was scheduled in 1981 on the basis of inaccurate assumptions about the legality of separate accounting, oil prices, and the projected decline of Prudhoe Bay

* It enhances the profitability of companies who claim their profits are "the best in the industry," who are searching around to buy new companies overseas, and who have themselves been partly bought up by the Kuwaiti national oil company.

* It provides unnecessary tax breaks for profitable fields but does not adequately enhance the profitability of truly marginal fields such as Milne Point.

Does the tax break pay off for Alaska?

* It removes $185-225 million per year from the state budget and the Alaska economy. This probably equates to about 4,000 jobs (20 jobs per million dollars).

* It might create some incentive to increase drilling activity on the North Slope, but this has not been proven. From 1/87 to 2/88 the North Slope rig count increased by three. (Usually there are 50-200 jobs per rig, many of which are taken by outside labor.)

* ARCO announced in 7/87 that it would be adding a rig (restoring one removed in 3/87) and that increased development activity was "strictly the result of higher oil prices."

* In 2/88 ARCO announced North Slope enhanced recovery plans that will cost $3 billion over ten years. They had already made the same announcement in 5/87. The tax break might not have had any effect at all on enhanced recovery plans; it might lead to hastier rather than increased oil production.

What can be done?

* The Senate can pass CSHB 164 (Fin), converting to a field-based economic limit factor that will eliminate

1987 tax break and enhance the profitability of all Alaska fields except Prudhoe and Kuparuk.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version: CS HB 164 (FIN) AM
REQUEST
Publish Date:

Revision Date: April 14, 1987
Title: An Act Relating to the Oil and Gas Production Tax
Sponsor: Rules/Governor
Requestor:

Agency Affected:
BRU:
Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	680	88140	10804	11800	11576	12317

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: Attach a separate page if necessary

This bill would change the Economic Limit Factor (ELF) to introduce field size as a consideration in establishing the effective severance tax rate on oil production. Fields producing in excess of roughly 120,000 barrels per day will have a higher rate than currently calculated. Other fields will have a lower rate.

Prepared By: Charles L. Logsdon (Vincent Wright for) Phone: 276-5364
Division: Commissioner's Office Date: April 20, 1987

Approved by Commissioner: Hugh Malone Date: April 21, 1987
Agency: Department of Revenue

Distribution (by Agency preparing fiscal note):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

Sam
he should have used the $175 million statistic, & compared it to the Interstate (Bradley or something completion?)

March 2, 1988

The Honorable Mitch Abood
Chairman
Committee on State Affairs
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Mr. Chairman:

I am writing to request an early hearing on CSHB 164(Fin) amended, the so-called "ELF" bill.

In July of last year the economic limit factor (ELF) began reducing production taxes in the Prudhoe Bay field. This came as no surprise; administration officials testified to this last year in the House. Since then, however, new information has become available suggesting that the ELF factor is creating an incentive for operators to drill additional wells, and that as a result the revenue losses resulting from the ELF will be substantially larger than anticipated. Moreover, according to other recent indications, the current ELF may be creating an unexpectedly large obstacle to the development of some small and marginal fields.

These new developments obviously have important ramifications for the state's fiscal condition, for our management of the state's oil resources, and for the consideration of CSHB 164. My administration looks forward to an early opportunity to present testimony on these critical matters before your committee.

Sincerely,

Steve Cowper
Governor

FISCAL EFFECTS OF ELF ALTERNATIVES

Additional Revenue (Millions) At the 30th percentile

	FY 87-88	FY 89	FY 90	FY 91	FY 92
HB-164	*76.7*	*92.0*	*98.5*	*99.9*	*105.6*
Proposed CSHB-164 (Res.)*	*98.6*	*98.1*	*109.6*	*96.1*	*94.2*

FY93
HB-164 → Ø.
Proposed CSHB-164 (Res.)* → 90+.

*Indicates provisional OMB estimate pending DOR fiscal analysis due next week.

I want to see 15-yr. projections

ESTIMATED SEVERANCE TAX RATES*

	Prudhoe Bay	Kuparuk River	Milne Point	Endicott	Lisburne	McArthur River	Granite Point
Current Law	12.6%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
HB-164	15.0%	7.8%	6.5%	5.6%	12.3%	1.1%	1.3%
Proposed CSHB-164 (Res.)	14.8%	10.7%	0.3%	0.3%	3.6%	0.0%	0.0%

*North Slope values are forecast FY 88 averages; Cook Inlet values are estimated Dec 1986 rates; Cook Inlet fields not listed have zero effective rates under all alternatives.

OMB, Division of Policy, 3/18/87

A M J

Sam revised ELF fiscal note

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version: CS HB 164 (FIN) am
Publish Date:

REQUEST

Revision Date: April 14, 1987
Title: An Act Relating to the Oil and Gas Production Tax
Sponsor: Rules/Governor
Requestor:

Agency Affected:
BRU:
Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	800	88140	10804	11300	11578	12517

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: Attach a separate page if necessary

This bill would change the Economic Limit Factor (ELF) to introduce field size as a consideration in establishing the effective severance tax rate on oil production. Fields producing in excess of roughly 120,000 barrels per day will have a higher rate than currently calculated. Other fields will have a lower rate.

Prepared By: Charles L. Logsdon (Vincent Knight for)
Phone: 276-3364
Division: Commissioner's Office
Date: April 20, 1987

Approved by Commissioner: Hugh Malone
Date: April 21, 1987
Agency: Department of Revenue

Distribution (by Agency preparing fiscal note):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)
Senate Secretary

MEMORANDUM

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

April 14, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist CL

Subject: CSHB164

We have recently made another run of the Petrev model to prepare estimates of the fiscal impact of CSHB164 passed by the House of Representatives. The only change made in this legislation not examined in prior fiscal notes was allowing either the taxpayer or the department to rebut the 300 barrels per well day presumed production at the economic limit (PEL). The fiscal note we prepared for the original CSHB164 fixed the PEL at 300 barrels per well day.

The fiscal impact of the final version is almost exactly the same as with the PEL fixed at 300 (Table 1). As might be expected, the lower PEL (department rebuts) dominates the higher PEL (comany rebuts)in both the 30% or downside risk case and the mean except for the near term when very low prices are a distinct possibility. That is, we would expect severance taxes to be higher the higher the price of oil because the PEL would be lower and consequently the ELF would be higher. In general however it turns out that given our assumptions about the probabilty distribution of oil prices, the higher PELs and lower PELs tend to offset each other with the result that the final outcome at both the Mean and 30% levels is not that much different than if the PEL were fixed at 300.

The revenue and production effects of the final version of CSHB164 as well as a comparison of effective tax rates by field for current law and CSHB164 are found in the following tables.

Table 1
The Effect on Fiscal Impact of CSHB164
With and Without PEL Fixed at 300
(Million $)

Fiscal Year	PEL Variable 30%	PEL=300 Fixed 30%	Impact Variable 30%	PEL Variable Mean	PEL=300 Fixed Mean	Impact Variable Mean
1988	88.14	88.69	-.55	108.21	109.41	-1.2
1989	108.04	108.49	-.45	129.96	129.93	.03
1990	118	117.56	.44	142.09	140.61	1.48
1991	115.76	112.39	2.37	143.3	140.23	3.07
1992	123.17	117.76	5.41	144.3	139.63	4.68
1993	134.65	129.08	5.57	147.22	138.85	8.38
1994	118.62	110.41	8.21	140.17	131.58	8.59
1995	113.31	102.41	10.9	136.02	128.49	7.53
1996	110	97.7	12.3	133.88	123.89	9.99
1997	112.94	100.35	12.49	136.74	122.39	14.35
1998	102.16	88.16	14	136.93	121.19	15.74
1999	104.76	90.94	13.82	134.24	119.36	14.88
2000	83.06	69.02	14.04	140.05	123.15	16.9
2001	75.71	62.84	12.87	141.23	123.61	17.62
2002	68.01	59.11	8.9	139.01	121.55	17.46
2003	59.48	50.11	9.37	137.31	118.3	19.01
2004	41.69	30.51	11.18	129.49	108.62	20.87
2005	29.03	21.14	7.89	102.3	88.98	13.32

Table 2
Comparison of the March 1987 DOR Petroleum Production
Revenue Forecast and CSHB164
(Million $)

Fiscal Year	March Official 30%	CSHB164 30%	March Official Mean	CSHB164 Mean	Delta 30%	Delta Mean
1987	1108.87	1114.39	1162.46	1168.36	5.52	5.9
1988	1139.59	1277.73	1437.59	1545.8	88.14	108.21
1989	1319.14	1427.13	1630.02	1759.88	108.04	123.96
1990	1441.42	1559.42	1760.32	1905.31	118	142.09
1991	1330.42	1446.13	1656.31	1800.41	115.76	143.6
1992	1431.66	1554.83	1803.98	1959.48	123.17	144.5
1993	1503.92	1638.57	1937.47	2084.7	134.65	147.23
1994	1550.06	1668.68	2239.29	2429.46	118.62	140.17
1995	1512.66	1625.97	2368.06	2504.08	113.31	136.02
1996	1470.59	1580.59	2329.13	2463.01	110	133.88
1997	1455.73	1568.57	2695.79	2832.53	112.84	136.74
1998	1424.09	1526.25	2658.19	2795.12	102.16	136.93
1999	1366.82	1471.58	2594.32	2728.56	104.76	134.24
2000	1312.73	1395.79	2541.24	2681.29	83.06	140.05
2001	1269.4	1345.11	2489.63	2630.86	75.71	141.23
2002	1223.23	1291.24	2454.13	2593.14	68.01	139.01
2003	1198.75	1258.23	2537.33	2674.64	59.48	137.31
2004	1174.99	1216.68	2516.98	2646.47	41.69	129.49
2005	1161.32	1190.35	2486.44	2588.74	29.03	102.3

Table 3
Production Impact of CSHB164
(Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1988	0	0	.28	0	0	0	0	0	.28
1989	0	0	.3	0	0	0	0	0	.3
1990	0	0	.28	0	0	0	0	0	.28
1991	0	0	.24	0	0	0	0	0	.24
1992	0	0	.21	.03	0	0	.46	0	.7
1993	0	0	.21	.03	0	0	.83	0	1.07
1994	-1.47	-.05	.2	.02	-.79	0	.87	0	-1.22
1995	-1.29	-.04	.44	.07	-.7	-.84	.8	0	-1.56
1996	-1.13	-.03	.46	.07	-.62	-.97	.81	0	-1.41
1997	-2.47	-.02	.46	.05	-.55	-1.21	.86	0	-2.88
1998	-2.17	-.02	.38	.04	-.49	-1.07	.79	.27	-2.27
1999	-1.9	-.02	.29	.04	-.43	-1.18	.53	.39	-2.28
2000	-1.67	-.01	.19	.02	-.38	-1.17	.29	.38	-2.35
2001	-1.46	0	.15	.01	-.35	-.96	.14	.39	-2.08
2002	-1.37	0	-.01	.01	-.31	-1.09	.09	.5	-2.18
2003	-1.13	.01	-.09	-.01	-.27	-.76	-.02	.55	-1.72
2004	-1.16	0	-.11	0	-.24	-1.13	-.12	.5	-2.26
2005	-1.12	-.02	-.07	0	-.22	-.66	-.19	.49	-1.78
									0
									0
Total	-18.34	-.2	3.82	.36	-5.35	-11.03	6.14	3.47	-21.11

Table 4
Increase (Decrease) in Average Severance Tax Rate With CSHB164

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore
1988	.0216	.0361	-.0480	-.0590	-.0585	0	0	0
1989	.0209	.0358	-.0438	-.0043	-.0266	0	0	0
1990	.0219	.0357	-.0360	-.0038	-.0118	0	0	0
1991	.0240	.0344	-.0513	-.0038	-.0009	0	0	0
1992	.0236	.0325	-.0544	-.0037	.0024	0	0	0
1993	.0235	.0295	-.0555	-.0044	.0107	0	-.0518	0
1994	.0215	.0255	-.0544	-.0146	.0146	0	-.0533	0
1995	.0219	.0219	-.0551	-.0200	.0143	.0037	-.0522	0
1996	.0231	.0163	-.0564	-.0277	.0141	.0116	-.0501	0
1997	.0223	.0111	-.0571	-.0306	.0138	.0157	-.0481	0
1998	.0235	.0043	-.0563	-.0281	.0136	.0162	-.0541	0
1999	.0246	-.0015	-.0532	-.0200	.0120	.0171	-.0506	-.0836
2000	.0256	-.0070	-.0507	-.0113	.0104	.0192	-.0546	-.0747
2001	.0252	-.0103	-.0422	-.0041	.0086	.0227	-.0509	-.0724
2002	.0247	-.0076	-.0280	-.0017	.0056	.0210	-.0501	-.0743
2003	.0239	-.0040	-.0251	-.0007	.0001	.0221	-.0546	-.0792
2004	.0231	-.0001	-.0453	-.0007	-.0034	.0213	-.0521	-.0911
2005	.0219	0	-.0505	-.0114	-.0073	.0036	-.0484	-.0960

Sam -
good tables at
the back on %
of income

STATE OF ALASKA
DEPARTMENT OF REVENUE
OFFICE OF THE COMMISSIONER

M E M O R A N D U M

TO: Vince Wright
Chief of Research

FROM: John Larson
Economist

DATE: March 23, 1987

SUBJECT: Standard Alaska Petroleum
Corporations's HB 164 Analysis

Standard Alaska Petroleum Corporation has developed an analysis which indicates the percentage of petroleum production net income, from all Alaskan producing fields (North Slope and Cook Inlet), which the state would collect from petroleum production revenues, over the period from FY 1988 through FY 1992, both under current law and under HB 164. The FY 1988 through FY 1992 period was chosen because HB 164 would extend the rule, setting the Petroleum Production Tax ELF equal to 1 if it is greater than .7 for the first 10 years of production from a field, to the first 15 years of production. Sadlerochit is the only field for which the ELF is greater than .7 and the proposed 15 year rule would apply to Sadlerochit through 1992. Thus HB 164 would only impact Sadlerochit and only for the FY 1988 through FY 1992 period. Standard's analysis was derived directly from $9 per barrel wellhead value scenario in the HB 353 Sensitivity Analysis which was published by the Department of Revenue in December 1986. The analysis shows that the state would collect 96 percent of production net income under current law and 102 percent of production net income under HB 164 over the period in question.

While the information in Standard's analysis is consistent with the information presented in the Department of Revenue's HB 353 Analysis, it may be somewhat misleading for the following reasons:

1) The idea of analysing the percentage of income from petroleum production activities within Alaska which the state collects from petroleum production revenues may be useful. However, the issue of how to define the total income or benefit resulting from production activities needs to be considered. The way in which Standard has structured its analysis assumes the benefits or income from oil production end at the wellhead. This would be a valid approach if the Alaska North

Slope (ANS) producers were only producing Alaskan oil and selling it through "arms length" transactions on the world market. However, the real situation is that the ANS producers are also involved in transportation, refining and marketing of ANS crude within their own integrated business. Therefore to arbitrarily limit the net income percentage share analysis to the wellhead may significantly understate the income which ANS producers actually derive from ANS production. Even the inclusion of TAPS income, ANS producers also own TAPS, in the analysis would not present a complete picture of the economics of ANS production for the producers.

2) The concept of net income which is used in the Standard analysis is valid for taxation purposes but has little meaning in the economic analysis. The calculation of net income from a taxation standpoint allows the deduction of depreciation and amortization. While depreciation and amortization do represent legitimate tax deductions, they also represent a cash flow benefit to the producers. Investment and operating decisions are based on net cashflow not net income. State production revenues would be a significantly smaller percentage of production net cashflow than of production net income. This point, along with the points raised in 1) above explain why the producers are still operating and making production capital investments even though according to Standard the state is taking nearly 100 percent of net income.

3) Insofar as HB 164 is concerned, it would be more valid to look at production net income, net cashflow and state production revenues for the Sadlerochit field alone rather than for all Alaskan fields as Standard has done. This is because HB 164 only impacts Sadlerochit as discussed above. The attached Table I presents Sadlerochit production net income and net cashflow for the period from FY 1988 through FY 1992 based on the assumptions of the $9, $11 and $13 per barrel scenarios in the December 1986 HB 353 Sensitivity Analysis. The table also shows state production revenues for the period under both current law and HB 164 as a percentage of both net income and net cashflow for each of the three wellhead value scenarios. Note that state production revenues as a percentage of net income in the $9 per barrel wellhead value scenario are 65 percent under current law and 71 percent under HB 164 compared to the 96 percent and 102 percent respectively which are shown in Standard's analysis under the same scenario but using all Alaskan fields rather than just Sadlerochit. When state production revenues are analysed as a percentage of net cashflow rather than net income the percentages drop to 40 percent under current law and 43 percent under HB 164. Also, note that if higher wellhead value scenarios are considered the state production revenue percentages of both production net income and net cashflow decline. Finally it should be remembered that in this analysis of Sadlerochit, income and cashflow, are defined at the wellhead and as discussed in 1) above there are additional benefits which accrue to the producers from this production.

4) Subsequent to Standard's analysis of HB 164 a new version of ELF legislation has been introduced, CSHB 164. Like HB 164, CSHB 164 would freeze the PEL in the ELF formula at 300 barrels per well per day. However CSHB 164 would eliminate the .7 rule and introduce a 55,000,000 scaling factor into the ELF formula. Thus beginning in FY 1988 the effective ELF would be the calculated ELF using the fixed PEL of 300 and the 55,000,000 scaling factor for all fields. The effect of this change would be to increase the effective ELF and thus Petroleum Production Tax for any field with production greater than 43.6 million barrels per year (119,452 barrels per day) and to reduce the effective ELF and Petroleum Production Tax for any field with production less than 43.6 million barrels per year. Under the assumptions of the $9 per barrel WHV scenario of the December 1986 HB 353 Sensitivity Analysis, the Petroleum Production Tax, for the FY 1988 through FY 1992 period, would be increased for Sadlerochit and Kupuruk and decreased for all other North Slope fields under the provisions of CSHB 164. The total North Slope revenue impact of CSHB 164 would be $496.80 million with $427.54 million due to Sadlerochit compared to $483.14 million, all due to Sadlerochit, under HB 164. Under CSHB 164 Sadlerochit would account for over 85 percent of the total revenue increase over the period. Table II shows the impact of CSHB 164 on the Sadlerochit field under the same set of assumptions as Table I shows for HB 164.

Table I
SADLEROCHIT OIL FIELD
Analysis of State Oil Production Revenues
With & Without Enactment of HB 164
As a Percentage of
Oil Production Net Income & Net Cash Flow
Based on 12/86 HB 353 Sensitivity Analysis
Sum FY 1988 - 1992

($ = millions 1986 $)

Wellhead Value Scenario	(1) Net Income	(2) State Revenue w/o HB164	(3) Revenue As % Of Net Income	(4) Revenue Impact HB 164	(5) State Revenue w/HB164	(6) Revenue As % Of Net Income
$9	8597.02	5590.58	65.03%	483.14	6073.72	70.65%
$11	12941.92	6636.80	51.28%	590.02	7226.82	55.84%
$13	17474.99	7669.42	43.89%	697.87	8367.29	47.88%

	(7) Net Cashflow	(8) State Revenue w/oHB164	(9) Revenue As % Of Net Cash Flow	(10) Revenue Impact HB 164	(11) State Revenue w/HB 164	(12) Revenue As % Of Net CashFlow
$9	13971.28	5590.58	40.01%	483.14	6073.72	43.47%
$11	18257.29	6636.80	36.35%	590.02	7226.82	39.58%
$13	22518.88	7669.42	34.06%	697.87	8367.29	37.16%

Assumptions:

1. HB 164 extends the .7 ELF rule for Sadlerochit for 5 years from FY 1988 through FY 1992 and freezes the PEL at 300. The impact of HB 164 on state revenues is shown in columns (4) and (10).

2. Net income in column (1) is derived by deducting the following non-tax items from gross income: Operating costs, depreciation and amortization. Administration, overhead and uncapitalized interest expenses for the total North Slope are allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

3. Net cashflow in column (7) is derived by adding back depreciation and amortization to net income in column (1).

4. State oil production revenues under current law without HB 164 in columns (2) and (8) and with HB 164 in columns (5) and (11) include oil royalties, oil production taxes and oil conservation taxes. Also included is Petroleum Corporate Income Tax under the current modified apportionment law allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

Table II
SADLEROCHIT OIL FIELD
Analysis of State Oil Production Revenues
With & Without Enactment of CSHB 164
As a Percentage of
Oil Production Net Income & Net Cash Flow
Based on 12/86 HB 353 Sensitivity Analysis
Sum FY 1988 - 1992

($ = millions 1986 $)

Wellhead Value Scenario	(1) Net Income	(2) State Revenue w/oCSHB164	(3) Revenue As % Of Net Income	(4) Revenue Impact CSHB164	(5) State Revenue w/CSHB164	(6) Revenue As % Of Net Income
$9	8597.02	5590.58	65.03%	427.54	6018.12	70.00%
$11	12941.92	6636.80	51.28%	522.54	7159.34	55.32%
$13	17474.99	7669.42	43.89%	617.56	8286.98	47.42%

	(7) Net Cashflow	(8) State Revenue w/oCSHB164	(9) Revenue As % Of Net Cash Flow	(10) Revenue Impact CSHB 164	(11) State Revenue w/CSHB 164	(12) Revenue As % Of Net CashFlow
$9	13971.28	5590.58	40.01%	427.54	6018.12	43.07%
$11	18257.29	6636.80	36.35%	522.54	7159.34	39.21%
$13	22518.88	7669.42	34.06%	617.56	8286.98	36.80%

Assumptions:

1. CSHB 164 introduces a 55,000,000 scaling factor into the exponent of the current ELF formula and fixes the PEL at 300 barrels per well per day. The impact of CSHB 164 on state revenues is shown in columns (4) and (10).

2. Net income in column (1) is derived by deducting the following non-tax items from gross income: Operating costs, depreciation and amortization. Administration, overhead and uncapitalized interest expenses for the total North Slope are allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

3. Net cashflow in column (7) is derived by adding back depreciation and amortization to net income in column (1).

4. State oil production revenues under current law without CSHB 164 in columns (2) and (8) and with CSHB 164 in columns (5) and (11) include oil royalties, oil production taxes and oil conservation taxes. Also included is Petroleum Corporate Income Tax under the current modified apportionment law allocated to Sadlerochit based on the ratio of Sadlerochit oil production to total North Slope oil production.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST

Bill Version: CS HB 164
Publish Date:

Pevision Date:
Title: An act relating to the oil and gas production tax.
Sponsor: Rules/Goverror
Requestor: House Resources

Agency Affected: Revenue
BRU: Audit

Components: Oil & Gas

EXPENDITURES/REVENUES: (Millions of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	-	88.7	108.5	117.6	112.9	117.8

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: The above numbers represent the increase in general fund revenues if this bill becomes law. The key assumptions are introduction of a 55,000,000 scaling factor into the exponent of the current ELF formula and fixing the value of the Production at the Economic Limit (PEL) at 300 barrels per well per day. The production impact from FY88 through FY2005 represents a cumulative total loss of 20.9 million barrels.

Prepared By: Chuck Logsdon
Division: Office of the Commissioner

Phone: 276-5364
Date: 3/19/87

Approved by Commissioner:
Agency: Revenue

Date: 3/19/87

Distribution (by Agency preparing fiscal note):
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Alaska State Legislature

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IN SESSION:
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Senator Mitch Abood
CHAIRMAN

Senate Committee on State Affairs

MEMORANDUM

TO: All Members of the Alaska Legislature

FROM: Senator Mitch Abood, Chairman
Senate Committee on State Affairs

DATE: May 2, 1988

SUBJECT: CS for House Bill 164, the so-called ELF bill

As I promised last week, Elfie has gone through the "Oil Tax Quiz" that the Governor's number crunchers put out April 15th. Today Elfie is reporting on the first 3 questions from the quiz.

Elfie just can't believe how the Governor's number crunchers keep on makin' more mistakes. And Elfie is curious that IF their manipulating of the numbers is not a "deliberate attempt to deceive the public" THEN WHAT IS IT?

Elfie is also glad that "legislators and the public are not being fooled" by the Governor's number crunchers.

GOVERNOR'S NUMBER CRUNCHER ERROR VI:

Question 1 on the oil tax quiz was:

1. How much profit does the oil industry make each day from North Slope oil and the pipeline?

___ A. The industry is making no profit on the Slope.
___ B. $800,000 per day.
___ C. $2,200,000 per day.
___ D. $6,200,000 per day.

The Governor's number crunchers said the correct answer is D. The truth is that the correct answer would be "None of the above." The number crunchers cite Petroleum Intelligence Weekly for their answer to this question, but some of PIW's cost figures are incorrect.

For example, PIW's figure ($0.15 per barrel) for state and municipal property taxes works out to a total property tax of $109.5 million. But the Department of Revenue's own 1988 assessed value of the North Slope fields and pipelines is $16.95 billion. With the total tax rate at 20 mills (2%), **THE TAX FOR THESE PROPERTIES IS $339 MILLION, NOT $109 MILLION**, which makes the true property tax per barrel for 1988 **$0.46 -- NOT $0.15.**

The Governor's number crunchers also ignored the Department of Revenue's own estimate of the production costs for North Slope fields, probably because it is higher that PIW's figure. According to the Department of Revenue, production costs in 1988 are $1.61 **PER BARREL**, not the $0.85 figure from PIW.

With just these 2 corrections to the numbers, the **INDUSTRY'S PROFIT DROPS** from $3.03 per barrel to $1.92. The state and local share **GOES UP** by the $0.31 per barrel which was **LEFT OUT** of PIW's property tax figure, to a total of $2.68 per barrel or $5.4 million a day.

From this information it is also clear that the Governor's number crunchers answer to their second question is also wrong.

GOVERNOR'S NUMBER CRUNCHER ERROR VII:

Question 2 on the oil tax quiz was:

2. How do state and industry shares of North Slope oil income compare?

___ A. State and local 80%/industry 5%/ feds 15%.
___ B. State and local 60%/industry 15%/feds15%.
___ C. State and local 45%/industry 35%/feds 20%.
___ D. State and local 35%/industry 45%/feds 20%.

The Governor's number crunchers said the correct answer is D, even though it is clear that the state and local government's are making 40% more ($2.68 per barrel) than industry ($1.92 per barrel), using the corrected PIW figures. **THE DEPARTMENT OF REVENUE'S OWN ANALYSIS CONFIRMS THIS RESULT.** The Department has figured that the state and local share is 57% for this year at $15 - $16 market prices, and they have predicted that this figure will rise to 67% by 1991 (see Elfie memo of March 23).

GOVERNOR'S NUMBER CRUNCHER ERROR VIII:

Question 3 on the oil tax quiz was:

3. How many new jobs has the oil industry created on the North Slope since the ELF became effective at Prudhoe Bay in June of 1987?

___ A. 2,400 jobs.
___ B. 800 jobs.
___ C. 200 jobs.
___ D. Oil industry jobs on the Slope appear to have declined.

The Governor's number crunchers said D, ignoring the simple arithmetic that shows A is correct. There are currently 8 drilling rigs working on the North Slope. Elfie's experience shows that each rig creates 50 to 100 direct jobs, and at least another 200 indirect jobs. **THIS MEANS 250 TO 300 JOBS ARE CREATED FOR EACH RIG THAT IS WORKING. 8 RIGS MEANS 2,000 - 2,400 JOBS!!!!**

The Governor's number crunchers point to Department of Labor statistics showing that the number of jobs on the Slope was less in the 4th quarter of 1987 that in the 4th quarter of 1986. **THESE STATISTICS DON'T SAY ANYTHING ABOUT HOW MUCH MORE THE NUMBER OF JOBS WOULD HAVE DECLINED ON THE SLOPE IF THE 8 RIGS WERE IDLE.** Also, since the Commissioner of the Department of Labor has personally been dragged into the ELF debate as a "CONDUIT" by the number crunchers, Elfie is wondering whether his statistics weren't "cooked" a little bit in order to win entry into the Governor's number crunchers' inner circle.

THE NUMBER CRUNCHERS ALSO IGNORED EVIDENCE BY THE SUPPORT INDUSTRY ALLIANCE THAT THE ELF HAS BEEN CREATING NEW JOBS. Out of more that 200 members in the Alliance, 79 reported a total gain of 636 employees in the first 10 months that the ELF was back in effect for Prudhoe Bay, and they expect the total gain to be over 1,000 new jobs by the end of its first year.

THE GOVERNOR'S NUMBER CRUNCHERS SCORED A BIG, FAT ZERO FOR EACH OF THE FIRST 3 QUESTIONS. Attached are the copies from the Department of Revenue's study where Elfie found the straight facts.

The real truth hasn't changed. **ELF IS WORKING, AND WORKING WELL.** It is creating jobs for Alaskans. It is stimulating economic activity in Alaska. It is increasing recoverable oil reserves.

As has been proven over and over, the solution to Alaska's economic problems is not increasing taxes in order to fuel the big spending House Majority and Governor's proposed 16% budget increase.

The Governor's number crunchers will continue to take the **"OPPORTUNITY TO MAKE OUR CASE ON THE ELF IF AND WHEN THE OIL COMPANIES TELL THE SENATE THEY CAN LET US HAVE A PUBLIC HEARING."** Now what do you think I got the above quote from??? **BOY HOWDY, AIN'T THEY SLICK!!!!**

AND WOULD YOU BELIEVE, THERE'S MORE TO COME!!!

SENSITIVITY ANALYSIS
OF
PROJECTED REVENUE COLLECTIONS

HB 353

COMPARED TO

CURRENT LAW

ALASKA DEPARTMENT OF REVENUE
DECEMBER 1986
By
John Larson, Economist
Charles Logsdon, Petroleum Economist
Roger Marks, Petroleum Economist

TABLE II-11-1
ALL NORTH SLOPE PRODUCING FIELDS SEPARATE ACCT (HB333) INCOME TAX ESTS
10-1986 01 SENSITIVITY ANALYSIS $11/B WW

FISCAL YEAR	PROD VOL WT AVG GROSS WELLHEAD VALUE $/B	TOTAL GROSS PROD VOL MMB/Y	TOTAL GROSS REV MM$/Y	ROYALTY SHARE MM$/Y	PROD & CONS TAX MM$/Y	PTY TAX MM$/Y	OPER COSTS MM$/Y	DEPREC EXPENSE MM$/Y	AMORT EXPENSE MM$/Y	UNCAP INTEREST EXPENSE ALLOWED MM$/Y	ADMIN & OVERHD EXPENSE ALLOWED MM$/Y	EXPLOR (UNSUCCS) EXPENSE ALLOWED MM$/Y	TOTAL DEDUCT MM$/Y	TOTAL TAXABLE INCOME MM$/Y	TOTAL TAX LIAB MM$/Y	WINDFALL PROFITS TAX MM$/Y	TOTAL DEDUCT W/WPT MM$/Y	TOTAL TAXABLE INCOME W/WPT MM$/Y	TOTAL TAX LIAB W/WPT MM$/Y	PROD TAX CURRENT MM$/Y	PROD TAX HB333 MM$/Y
1986	10.81650	631.00	7041.50	855.84	810.65	314.01	1137.47	1327.00	0.51	105.00	240.00	176.00	4926.16	2115.30	198.05	0.00	4926.16	2115.30	198.05	859.94	859.94
1987	10.70010	661.00	7131.19	852.99	701.34	236.69	1152.16	1555.63	30.29	105.00	240.00	176.00	5125.06	2006.15	188.50	0.00	5125.00	2006.15	188.50	863.90	700.61
1988	10.72040	637.00	6813.99	876.60	559.18	250.70	1172.17	1400.40	16.85	105.06	240.00	176.00	5056.52	1777.47	167.00	0.00	5056.52	1777.47	167.00	679.71	550.79
1989	10.61611	637.00	6761.19	810.65	502.43	256.44	1191.09	1816.22	72.11	105.00	240.00	176.00	5207.30	1513.01	142.36	0.00	5207.30	1513.01	142.39	653.50	544.74
1990	10.59110	602.00	6376.19	772.74	502.70	246.02	1155.06	1800.97	77.96	105.00	240.00	176.00	5077.25	1298.94	122.10	0.00	5077.25	1298.94	122.10	603.92	502.05
1991	10.57760	545.00	5766.79	690.96	442.30	212.76	1087.49	1752.63	77.06	105.00	240.00	176.00	4816.26	948.53	89.16	0.00	4816.26	948.53	89.16	537.10	441.79
1992	10.57127	490.00	5179.92	620.30	385.60	230.45	1020.67	1025.78	75.02	105.00	240.00	176.00	4699.70	480.13	45.13	0.00	4690.79	480.13	45.13	487.75	385.15
1993	10.56300	442.00	4881.05	593.30	361.04	217.55	1095.20	1966.78	74.59	105.00	240.00	176.00	4859.55	21.40	2.02	0.00	4859.55	21.40	2.02	441.10	360.50
1994	10.41152	421.00	4467.05	511.92	324.40	201.80	1030.06	1957.44	69.51	105.00	240.00	176.00	4715.04	-247.59	-23.27	0.00	4715.04	-247.59	-23.27	396.77	324.05
1995	10.40016	383.00	4060.16	492.31	294.28	230.07	1037.32	1811.77	61.99	105.00	240.00	176.00	4481.96	-421.80	-39.65	0.00	4481.96	-421.80	-39.65	359.05	293.07
1996	10.40070	340.00	3604.27	432.45	253.90	211.23	957.44	1631.93	53.63	105.00	240.00	176.00	4061.09	-457.62	-43.02	0.00	4061.09	-457.62	-43.02	310.55	253.61
1997	10.40593	300.00	3181.70	381.32	219.56	192.39	810.39	1423.66	44.46	105.00	240.00	176.00	3674.98	-493.28	-46.36	0.00	3674.98	-493.28	-46.36	268.45	219.23
1998	10.62517	260.00	2847.66	318.56	194.73	173.55	825.19	1259.39	37.29	105.00	240.00	176.00	3351.71	-504.11	-47.39	0.00	3351.71	-504.11	-47.39	238.00	194.43
1999	10.62814	242.00	2570.00	307.37	173.70	155.39	784.75	1131.56	32.69	105.00	240.00	176.00	3108.46	-537.66	-50.56	0.00	3108.46	-537.66	-50.56	212.37	173.46
2000	10.61156	208.00	2207.20	266.86	143.28	137.23	746.41	970.78	20.07	105.00	240.00	176.00	2810.63	-611.43	-57.47	0.00	2810.63	-611.43	-57.47	175.00	142.98
2001	10.01007	185.00	1881.00	234.05	136.95	119.06	665.45	730.37	13.95	105.00	240.00	176.00	2407.78	-426.78	-39.93	0.00	2407.78	-426.78	-39.93	164.99	136.75
2002	10.01727	165.00	1709.00	211.13	122.39	103.02	619.17	659.25	11.96	105.00	240.00	176.00	2210.72	-450.92	-43.10	0.00	2210.72	-450.92	-43.10	149.66	122.21
2003	10.85000	136.00	1475.60	171.19	103.74	88.50	564.52	493.45	0.10	105.00	240.00	176.00	1926.65	-451.05	-42.10	0.00	1926.65	-451.05	-42.10	126.00	103.59
2004	11.00000	107.00	1172.00	137.76	90.32	75.60	462.97	350.91	0.09	105.00	240.00	176.00	1618.65	-446.65	-41.52	0.00	1618.65	-446.65	-41.52	110.45	90.20
2005	11.00000	95.00	1045.00	122.31	79.80	66.15	431.62	311.56	0.00	105.00	240.00	176.00	1532.60	-487.60	-45.83	0.00	1552.60	-487.60	-45.83	97.69	79.70

TABLE II-II-8
PERCENTAGE SHARE COMPARISON
CALCULATION OF STATE PETROLEUM PRODUCTION REVENUES
AS A PERCENTAGE OF
PETROLEUM PRODUCTION NET INCOME
[illegible] SENSITIVITY ANALYSIS [illegible]

FISCAL YEAR	TOTAL PETRO PROD GROSS INCOME $MM/Y	TOTAL PETRO PROD NON TAX DEDUCTS $MM/Y	TOTAL PETRO PROD NET INCOME $MM/Y	CURRENT LAW STATE PETRO PROD REVENUE $MM/Y	REVENUE VS NET INCOME %	GROSS STATE PETRO PROD REVENUE $MM/Y	REVENUE VS NET INCOME %
1986	7500.08	3356.16	4144.73	2202.26	55.13	2215.11	53.46
1987	7557.01	3635.95	3921.09	2190.43	55.86	2119.93	54.57
1988	7277.08	3805.89	3471.99	1895.17	57.46	1890.47	54.65
1989	7207.41	4014.40	3192.72	1966.22	61.50	1849.82	57.94
1990	6870.36	3939.66	2930.70	1818.60	63.50	1746.29	59.42
1991	6362.27	3825.44	2536.83	1726.83	67.54	1583.36	62.44
1992	5855.26	3830.44	2024.82	1591.75	78.49	1449.40	71.59
1993	5591.09	4044.84	1557.25	1540.69	98.94	1366.06	87.72
1994	5333.36	3991.10	1342.18	1459.76	108.74	1296.90	96.61
1995	5130.65	3831.28	1287.45	1390.25	107.98	1256.29	97.57
1996	4675.48	3516.27	1159.21	1256.94	108.43	1145.32	98.80
1997	4214.21	3233.76	1010.42	1100.73	109.44	1014.24	100.36
1998	3941.08	2994.92	946.16	1018.41	108.58	967.01	100.17
1999	3671.89	2824.83	847.06	961.00	113.58	872.50	103.28
2000	3285.88	2610.13	675.75	853.46	126.30	795.24	117.76
2001	3016.17	2259.50	756.68	779.47	100.37	720.45	95.00
2002	2833.47	2131.31	702.16	721.85	102.76	670.60	95.61
2003	2482.18	1880.97	601.13	631.42	105.37	597.01	99.45
2004	2160.58	1634.80	525.78	557.56	106.05	529.50	100.72
2005	2016.81	1584.89	431.92	512.51	118.66	490.51	113.57

MEMORANDUM

STATE OF ALASKA

Department of Revenue

Petroleum Research Section

April 14, 1987

To: Vincent D. Wright, Chief of Research

From: Charles Logsdon, Petroleum Economist CL

Subject: CSHB164

We have recently made another run of the Petrev model to prepare estimates of the fiscal impact of CSHB164 passed by the House of Representatives. The only change made in this legislation not examined in prior fiscal notes was allowing either the taxpayer or the department to rebut the 300 barrels per well day presumed production at the economic limit (PEL). The fiscal note we prepared for the original CSHB164 fixed the PEL at 300 barrels per well day.

The fiscal impact of the final version is almost exactly the same as with the PEL fixed at 300 (Table 1). As might be expected, the lower PEL (department rebuts) dominates the higher PEL (comany rebuts)in both the 30% or downside risk case and the mean except for the near term when very low prices are a distinct possibility. That is, we would expect severance taxes to be higher the higher the price of oil because the PEL would be lower and consequently the ELF would be higher. In general however it turns out that given our assumptions about the probabilty distribution of oil prices, the higher PELs and lower PELs tend to offset each other with the result that the final outcome at both the Mean and 30% levels is not that much different than if the PEL were fixed at 300.

The revenue and production effects of the final version of CSHB164 as well as a comparison of effective tax rates by field for current law and CSHB164 are found in the following tables.

Table 1
The Effect on Fiscal Impact of CSHB164
With and Without PEL Fixed at 300
(Million $)

Fiscal Year	PEL Variable 30%	PEL=300 Fixed 30%	Impact Variable 30%	PEL Variable Mean	PEL=300 Fixed Mean	Impact Variable Mean
1988	88.14	88.69	-.55	108.21	109.41	-1.2
1989	108.04	108.49	-.45	128.96	128.93	.03
1990	118	117.56	.44	142.09	140.51	1.58
1991	115.76	112.89	2.87	143.6	140.53	3.07
1992	123.17	117.76	5.41	144.5	139.65	4.85
1993	134.65	129.08	5.57	147.23	138.85	8.38
1994	118.62	110.41	8.21	140.17	131.58	8.59
1995	113.31	102.41	10.9	136.02	128.49	7.53
1996	110	97.7	12.3	133.88	123.89	9.99
1997	112.84	100.35	12.49	136.74	122.39	14.35
1998	102.16	88.16	14	136.93	121.19	15.74
1999	104.76	90.94	13.82	134.24	119.36	14.88
2000	83.06	69.02	14.04	140.05	123.15	16.9
2001	75.71	62.84	12.87	141.23	123.61	17.62
2002	68.01	59.11	8.9	139.01	121.55	17.46
2003	59.48	50.11	9.37	137.31	118.3	19.01
2004	41.69	30.51	11.18	129.49	108.62	20.87
2005	29.03	21.14	7.89	102.3	83.98	18.32

Table 2
Comparison of the March 1987 DOR Petroleum Production
Revenue Forecast and CSHB164
(Million $)

Fiscal Year	March Official 30%	CSHB164 30%	March Official Mean	CSHB164 Mean	Delta 30%	Delta Mean
1987	1108.87	1114.39	1162.46	1168.36	5.52	5.9
1988	1189.59	1277.73	1437.59	1545.8	88.14	108.21
1989	1319.14	1427.18	1630.92	1759.88	108.04	128.96
1990	1441.42	1559.42	1753.22	1895.31	118	142.09
1991	1330.42	1446.18	1656.81	1800.41	115.76	143.6
1992	1431.66	1554.83	1808.98	1953.48	123.17	144.5
1993	1503.92	1638.57	1937.47	2084.7	134.65	147.23
1994	1550.06	1668.68	2289.29	2429.46	118.62	140.17
1995	1512.66	1625.97	2368.06	2504.08	113.31	136.02
1996	1470.59	1580.59	2329.13	2463.01	110	133.88
1997	1455.73	1568.57	2695.79	2832.53	112.84	136.74
1998	1424.09	1526.25	2658.19	2795.12	102.16	136.93
1999	1366.82	1471.58	2594.32	2728.56	104.76	134.24
2000	1312.73	1395.79	2541.24	2681.29	83.06	140.05
2001	1269.4	1345.11	2489.63	2630.86	75.71	141.23
2002	1223.23	1291.24	2454.13	2593.14	68.01	139.01
2003	1198.75	1258.23	2537.33	2674.64	59.48	137.31
2004	1174.99	1216.68	2516.98	2646.47	41.69	129.49
2005	1161.32	1190.35	2486.44	2588.74	29.03	102.3

Table 3
Production Impact of CSHB164
(Million bbls/yr)

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore	Total
1988	0	0	.28	0	0	0	0	0	.28
1989	0	0	.3	0	0	0	0	0	.3
1990	0	0	.28	0	0	0	0	0	.28
1991	0	0	.24	0	0	0	0	0	.24
1992	0	0	.21	.03	0	0	.46	0	.7
1993	0	0	.21	.03	0	0	.83	0	1.07
1994	-1.47	-.05	.2	.02	-.79	0	.87	0	-1.22
1995	-1.29	-.04	.44	.07	-.7	-.84	.8	0	-1.56
1996	-1.13	-.03	.46	.07	-.62	-.97	.81	0	-1.41
1997	-2.47	-.02	.46	.05	-.55	-1.21	.86	0	-2.88
1998	-2.17	-.02	.38	.04	-.49	-1.07	.79	.27	-2.27
1999	-1.9	-.02	.29	.04	-.43	-1.18	.53	.39	-2.23
2000	-1.67	-.01	.19	.02	-.38	-1.17	.29	.38	-2.35
2001	-1.46	0	.15	.01	-.35	-.96	.14	.39	-2.08
2002	-1.37	0	-.01	.01	-.31	-1.09	.09	.5	-2.18
2003	-1.13	.01	-.09	-.01	-.27	-.76	-.02	.55	-1.72
2004	-1.16	0	-.11	0	-.24	-1.13	-.12	.5	-2.26
2005	-1.12	-.02	-.07	0	-.22	-.65	-.19	.49	-1.78
									0
									0
Total	-18.34	-.2	3.82	.38	-5.35	-11.03	6.14	3.47	-21.11

Table 4
Increase (Decrease) in Average Severance Tax Rate With CSHB164

Fiscal Year	Prudhoe Bay	Kuparuk	Milne Point	Endicott	Lisburne	West Sak	Other Onshore	Other Offshore
1988	.0216	.0361	-.0480	-.0590	-.0585	0	0	0
1989	.0209	.0358	-.0438	-.0043	-.0266	0	0	0
1990	.0219	.0357	-.0360	-.0038	-.0118	0	0	0
1991	.0240	.0344	-.0513	-.0038	-.0009	0	0	0
1992	.0236	.0325	-.0544	-.0037	.0024	0	0	0
1993	.0235	.0295	-.0555	-.0044	.0107	0	-.0518	0
1994	.0215	.0255	-.0544	-.0146	.0146	0	-.0533	0
1995	.0219	.0219	-.0551	-.0200	.0143	.0037	-.0522	0
1996	.0231	.0163	-.0564	-.0277	.0141	.0116	-.0501	0
1997	.0223	.0111	-.0571	-.0306	.0138	.0157	-.0481	0
1998	.0235	.0043	-.0563	-.0281	.0136	.0162	-.0541	0
1999	.0246	-.0015	-.0532	-.0200	.0120	.0171	-.0506	-.0836
2000	.0256	-.0070	-.0507	-.0113	.0104	.0192	-.0546	-.0747
2001	.0252	-.0103	-.0422	-.0041	.0086	.0227	-.0509	-.0724
2002	.0247	-.0076	-.0280	-.0017	.0056	.0210	-.0501	-.0743
2003	.0239	-.0040	-.0251	-.0007	.0001	.0221	-.0546	-.0792
2004	.0231	-.0001	-.0453	-.0007	-.0034	.0213	-.0521	-.0911
2005	.0219	0	-.0505	-.0114	-.0073	.0036	-.0484	-.0960

MEMORANDUM

State of Alaska
Department of Law

TO: Mary Halloran
Director
Division of Policy
Office of Management and Budget
Office of the Governor

DATE: March 28, 1988

FILE NO.: 663-88-0432

TEL. NO.: 465-3600

SUBJECT: Retroactivity of HB 164

FROM: Richard D. Monkman
Assistant Attorney General

You requested our opinion as to whether CSHB 164(Fin) am ("HB 164"), which would retroactively apply changes to the economic limit factor in the Oil and Gas Properties Production Tax (AS 43.55), would be likely to be held constitutionally permissible. If not, you ask our advice on "the maximum degree of retroactive application that would likely be held permissible."

The short answer is that the sections which would make HB 164 retroactive to June 1, 1987, would probably be held constitutional. If the law was retroactive to January 1, 1988, it would certainly be held constitutional.

1. Article II. The first step in analysis is the Alaska Constitution, article II, section 18:

> Laws passed by the legislature become effective ninety days after enactment. The legislature may, by concurrence of two-thirds of the membership of each house, provide for another effective date.

This section was designed to give the public three months notice of a new law before it is applied to them - unless the legislature, by a two-thirds vote, provides otherwise. State v. A.L.I.V.E. Voluntary, 606 P.2d 769 (Alaska 1980). In line with this provision, the general state policy is against retroactive statutes, based on the philosophy that people "should be able to rely on existing laws with reasonable certainty." Norton v. State, ABC Board, 695 P.2d 1090, 1093 (Alaska 1985). Retroactive application of new laws requires an express statement in the statute itself:

> No statute is retrospective unless expressly declared therein.

AS 01.10.090.

The leading case on point is Atlantic Richfield v. State, 705 P.2d 418, 438 (Alaska 1985). In this challenge to Alaska's former "separate accounting" oil tax statute, the Supreme Court upheld retroactive application of the statute back from the date of enactment to the beginning of the calendar year. The bill in question was signed into law on July 8, 1978. It provided:

> * Sec. 4. This Act applies to taxable income earned or received after December 31, 1977.
>
> * Sec. 5. The Act takes effect immediately in accordance with AS 01.10.070(c).

Ch. 110 SLA 1978.

Retroactive application was challenged by the oil companies. The Supreme Court held that the statute was "properly retroactive to January 1, 1978," because (1) the statute expressly stated it was to be retroactive, in accord with AS 01.10.090 and (2) the two-thirds vote requirement on the immediate effective date clause was met. The Court rejected oil company arguments that a separate two-thirds vote was required for retroactivity:

> AS 01.10.090 states that "[n]o statute is retrospective unless expressly declared therein." A two-thirds vote requirement does not appear in that section, or elsewhere in Alaska law. The legislature, however, has recognized that where retroactive application of a portion or all of a bill is desired, an immediate effective date, which does require a two-thirds vote under article II, sec. 18 and AS 01.10.070(a), should be used in conjunction with the retroactivity section.

705 P.2d at 438, citing Legislative Affairs Agency, Manual of Legislative Drafting 11 (1977 ed.) and Uniform Rules of the Alaska State Legislature, Rule 10 (May 3, 1977); accord, Legislative Affairs Agency, Manual of Legislative Drafting 28-29 (1987 ed.).

The language of sections 3 and 4 of HB 164 is similar to the language approved by the Supreme Court in Atlantic Richfield. Ch. 110 SLA 1978. If passed by the legislature with the requisite two-thirds vote on the effective date clause, the bill is certain to pass this first constitutional hurdle. Without passage of the effective date clause by a two-thirds vote, the retroactive application section will be void, and the bill will operate prospectively only.

2. Due Process. The next constitutional question is whether the bill would offend guarantees of due process of law. Generally speaking, there is no vested right in any particular rate of taxation. Cohan v. Commissioner, 39 F.2d 540, 545 (2d Cir. 1930) (Learned Hand, J.). Both Congress and state legislatures can change tax statutes and apply the changes retroactively:

> Taxation is neither a penalty imposed on the taxpayer nor a liability which he assumes by contract. It is but a way of apportioning the cost of government among those who in some measure are privileged to enjoy its benefits and must bear its burdens. Since no citizen enjoys immunity from that burden, its retroactive imposition does not necessarily infringe due process, and to challenge the present tax it is not enough to point out that the taxable event, the receipt of income, antedated the statute.

Welch v. Henry, 305 U.S. 134, 146-147 (1935).

The federal rule on retroactivity is that "the application of an income tax statute to the entire calendar year in which enactment took place does not per se violate the Due Process Clause of the Fifth Amendment." United States v. Darusmont, 449 U.S. 292, 297 (1980). A tax rate "may be retroactively changed at the will of Congress at least for periods of less than twelve months; Congress has done so from the outset..." Cohan, 39 F.2d at 545, quoted in Darusmont, 449 U.S. at 298. The rule is based in large part on Congressional history:

> For more than seventy-five years it has been the familiar legislative practice of Congress in the enactment of revenue laws to tax retroactively income or profits received during the year of the session in which the taxing statute is enacted, and in some instances during the year of the preceding session.

Welch, 305 U.S. at 148.

The reason behind the federal rule seems to be based on questions of "fair notice", whether "the nature or amount of the tax could not have reasonably been anticipated by the taxpayer at the time of the particular voluntary act which the statute later made the taxable event." Walsh, 305 U.S. at 147. Changes to tax rates are presumed to be foreseeable. In Darusmont, for example, the Court flatly rejected a taxpayer's argument that ret-

roactivity of an income tax change was barred by due process concerns. The Court stated that the proposed rate increase had been under public discussion in the form of bills before Congress for about a year, and therefore, the taxpayer "had ample advance notice of the increase." 449 U.S. at 299. */

State courts generally follow the federal rule, noting that "[t]ax provisions, as key components in a system designed to fairly apportion the costs of government, seldom remain static. Rather, we expect them to change in response to changing conditions." Martin v. Board of Assessment Appeals, 707 P.2d 348, 354 (Colo. 1985). The Alaska Supreme Court, as noted above, approved retroactive application of the Oil Tax Act to the full year in which it was enacted. Atlantic Richfield. In another case, the Alaska court had "no doubt" that a license fee increase could have been retroactive to the start of the year of enactment, if the legislature had followed AS 01.10.090 and "stated expressly that it intended the revised fee schedule to be retroactive." State, ABC Board v. Odom, 671 P.2d 375, 377 (Alaska 1983), quoting United States v. Hudson, 299 U.S. 498, 500 (1937) ("it has been the practice of Congress to make [income tax statutes] retroactive for relatively short periods ... and repeated decisions of this court have recognized the practice and sustained it as consistent with the due process clause of the Constitution.").

Because HB 164, as written, goes back beyond the start of the calendar year in which it will be passed, we cannot absolutely assure you that the retroactivity section will be held constitutional. By contrast, there is "no doubt" that the bill could be retroactive to January 1, 1988. Odom, Atlantic Richfield. However, going back further is perhaps not an

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*/ The Court also rejected the taxpayer's argument, based on gift tax cases, that he "could have altered his behavior to avoid the tax if it could have been anticipated by him at the time the transaction was effected." Darusmont, 449 U.S. at 299. Gift taxes seem to be the only tax area where the Court has been receptive to arguments against retroactivity. The Court has refused to consider income in the same light as the "one time transaction" of a gift. "[A] tax on the receipt of income is not comparable to a gift tax. We cannot assume that stockholders would refuse to receive corporate dividends even if they knew that their receipt would later be subjected to a new tax or an increase of an old one." Welch v. Henry, 305 U.S. at 148-149.

insurmountable problem. The logic applied by both the United States and Alaska Supreme Courts to support the "calendar year" rule seems to apply equally well to this situation. The proposed effective date of May 31, 1987 is less than twelve months prior to the presumed date HB 164 will be enacted. Twelve months is a "short period," and was implicitly approved by the United States Supreme Court in Darusmont. The bill proposes to change tax rates, an area which is presumed to be subject to legislative change on a regular basis. In this particular case, the taxpayers have been on actual notice that the tax rate might be changed since HB 164 was introduced in January, 1987. Thus, it can be argued that the May 31, 1987 effective date does not violate due process. We believe the argument to be strong, but, given the widespread adherence to the "calendar year" approach by the courts, not absolutely certain of success.

RDM:nb