

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES
1514 SCOMM 55: JNT. SPEC. COMM. ON STATE TAX POLICY 8672
1986-1987 1314

1 gas companies doing business in Alaska. Clearly, if a
2 company were doing business only in Alaska then all of its
3 income would be taxable in Alaska. The tax act results in
4 multi-state companies being placed on the same basis as in-
5 state companies.

6 127. From an accounting and economic standpoint,
7 it is clear that separate accounting results in a more
8 reasonable estimate of Alaska's share of production income
9 from PSP formula apportionment.

10
11 EFFECTS OF SEPARATE ACCOUNTING ON TAPS

12 128. Pipelines have been treated as separate
13 accounting entities since the early days of pipeline
14 regulations. Interstate pipelines were regulated beginning
15 with the Hepburn Act in 1906. Specific accounting rules
16 were established by the Interstate Commerce Commission in
17 1914.

18 129. The oil pipeline accounting rules require
19 separate accounting for crude oil pipelines and for product
20 pipelines. Oil pipeline accounting rules are specified in
21 detail in 18 C.F.R. 352. Such rules require separate
22 reporting of pipeline accounts by integrated oil companies.

23 130. Interstate oil pipeline tariffs, and, hence
24 profits, are regulated as to reasonableness under the
25 Interstate Commerce Act. The basis on which the tariffs
26 and, hence the profits, are determined is not any of the
27 factors included in PSP formula apportionment.

28 132. The tariff for the pipeline is determined on
29 an allowable return basis. The tariff is in essence a
30 service fee and not a sales value. Since the tariff is
31 determined based on the allowed rate of return on assets,
32 the allowed profit determines the revenues. PSP formula
33 apportionment is based on the opposite assumption -- namely
34 that sales determine profits.

1 133. ARCO Pipeline, Sohio Pipeline, Exxon Pipeline
2 and all other interstate oil pipeline companies file 10-K
3 forms with the Securities and Exchange Commission separate
4 from their consolidated financial statements.

5 134. The oil pipelines also file a more
6 comprehensive annual report on Form P with the Federal
7 Energy Regulatory Commission. This report is separate from
8 the parent company's financial report and details revenues
9 and expenses of solely the pipeline companies.

10 135. Federal regulations require that for
11 regulatory purposes pipeline companies keep records of asset
12 values by individual state. Porter, S., Petroleum
13 Accounting Practices, New York: McGraw-Hill, p. 353
14 (1965).

15 136. In addition to federal regulation, oil
16 pipelines are required to maintain separate accounts for the
17 states in which they maintain intrastate operations. TAPS
18 is subject to federal regulation as an interstate pipeline.
19 However, because some crude is shipped intrastate, separate
20 accounts are required for the Alaska Public Utility
21 Commission. ARCO Pipeline Co., Annual Report, p. 1 (1978).

22 137. ARCO Pipeline Company, Exxon Pipeline Company
23 and Sohio Pipeline Company, which have pipeline operations
24 in states other than Alaska, must nonetheless report to the
25 Alaska Public Utility Commission income and expenses
26 associated solely with their separate Alaska operations.
27 All other TAPS owners have separate Alaska pipeline
28 subsidiaries.

29 138. Because the pipeline companies are separate
30 legal entities from the parent companies the income from the
31 pipeline companies is often excluded from the income
32 apportioned under formula apportionment methods. This was
33 the situation for South Carolina. Unless the pipelines are
34

1 treated separately a great deal of their income can escape
2 taxation altogether.

3 139. Respondents to the TAPS rate investigation
4 proceeding before the Federal Energy Regulatory Commission
5 have consistently argued that income for TAPS should be
6 determined based on a separate consideration of the project.
7 Respondents' Joint Reply Brief, p. 186-189; Exxon Pipeline
8 Co., Supp. Phase I Reply Brief, pp. 18-19; Phillips Alaska
9 Corp., Supp. Reply Brief, p. 7; Union Alaska Pipeline Co.,
10 Supp. Reply Brief, p. 11; Exxon Pipeline Co. Response (Mar.
11 2, 1978), pp. 16-20; Mobil Alaska Pipeline Co. Memorandum
12 (March 6, 1978), p. 4; U.S. Department of Justice, Proposed
13 Findings, p. 18; Union Alaska Supp. Brief, pp. 7-8. It
14 would be consistent to tax that income on a separate
15 accounting basis also.

16 140. Respondents to the TAPS proceedings argued
17 that TAPS is riskier than the oil industry in general and
18 riskier than lower-48 oil pipelines, and, hence, should be
19 allowed a higher rate of return to compensate for that
20 additional risk. Respondents' Joint Reply Brief, p. 292.
21 If the pipeline would thereby earn income that is
22 disproportionate to the assets employed in other segments of
23 the parent company's business, then the misallocations of
24 income illustrated in ¶ 65-77, supra, would also apply to
25 pipeline income attribution.

26 141. For each of these pipeline companies, the
27 investment in TAPS is overwhelmingly the largest property
28 item. For 1980, the TAPS property amounted to the following
29 percentages of total pipeline company property:

30	ARCO	85.4% (estimated)
	Exxon	80.9%
31	Sohio	98.9%

SUMMARY CONCLUSIONS - TAPS

142. Income for oil pipelines in general, and for TAPS as a specific case, is based on the value of the pipeline property, not on any of the elements in PSP formula apportionment. Therefore, it would only be by chance that PSP formula apportionment methods would result in an appropriate estimate of Alaska's share of income from TAPS. Moreover, separate accounting is the norm for pipeline rate making purposes and is also used as a basis for pipeline state income taxation. TAPS's owners (including the plaintiffs in this case) have emphasized the unique nature of the TAPS asset in rate-making proceedings. As a result of all this, it appears that the only reasonably certain way of estimating TAPS income is to use separate accounting as called for in AS 43.21.

DATED this 10th day of November, 1981.


Edward B. Deakin III

SUBSCRIBED AND SWORN to before me this _____
day of _____, 1981.

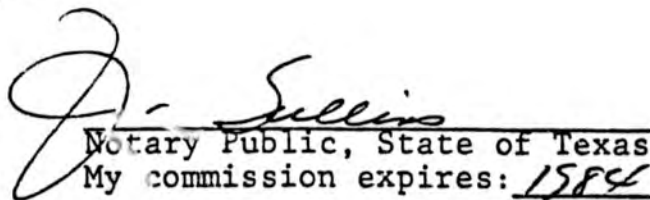

Notary Public, State of Texas
My commission expires: 1984

EXHIBIT I

October, 1981

VITA

NAME: Edward B. Deakin

ADDRESS: Office -- 306 BEB
University of Texas
Austin, Texas 78712

Phone -- 512-471-5215

ACADEMIC BACKGROUND: Ph.D., Accounting, 1972, University of Illinois at Urbana-Champaign
M.B.A., 1969, Drexel University, Philadelphia
A.B., 1965, Muhlenberg College, Allentown, Pennsylvania
C.P.A., Illinois, 1972; Texas, 1973

EMPLOYMENT BACKGROUND: 1981-date Professor, University of Texas at Austin
1978-1979 Visiting Associate Professor, Stanford University
1978 Visiting Professor, Kuwait University
1976-1981 Associate Professor, The University of Texas at Austin
1972-1976 Assistant Professor, The University of Texas at Austin
1970-1972 Graduate Assistant, Department of Accountancy,
University of Illinois at Urbana-Champaign
1968-1970 Instructor, Department of Business, Lehigh County
Community College, Schnecksville, Pennsylvania
1967-1968 Systems Analyst, First Pennsylvania Bank, Philadelphia
1965 Staff Accountant, Coopers & Lybrands, Philadelphia

HONORS AND AWARDS: 1974 - Learned Society Grant, University of Texas
1973 - Academic Development Award, College of Business Administration
Research Grant, Department of Accounting
1972 - Elijah Watts Sells Foundation Certificate, Honorable Mention,
May, 1972 CPA Exam
Arthur Andersen Doctoral Fellow
AICPA Dissertation Grant Awardee
Richard Irwin Foundation Dissertation Grant Awardee
1971 - American Accounting Association Fellow
Department of Accountancy, Price Waterhouse Fellowship,
University of Illinois
University Summer Fellow in Accountancy (University of
Illinois)
Beta Alpha Psi
1970 - Departmental Fellowship, University of Illinois
1965 - Pennsylvania Institute of CPA's Award, Muhlenberg College
1961 - Muhlenberg College Competitive Scholarship Holder
1960 - National Merit Finalist

PROFESSIONAL MEMBERSHIPS: American Accounting Association
American Institute of Certified Public Accountants
American Statistical Association
Texas Society of Certified Public Accountants

COMMITTEES: FASB Task Force on Oil & Gas Disclosure Issues, 1981
University Research Institute, 1981
Editor, Department Working Paper Series, 1981
Academic Development Committee, College of Business Administration, 1980
Dean's Advisory Committee to Select a New Chairman for the Department of Accounting, 1980
Committee on the Doctoral Consortium, American Accounting Association, 1980-81
Competitive Manuscript Committee, American Accounting Association (Chairman, 1977)
Editorial Board, The Accounting Review
Committee on Cost Accounting Standards, American Accounting Association
Courses and Curriculum Committee, College of Business Administration
Ph.D. Admissions and Continuance Committee, Department of Accounting
Policy and Advisory Committee, Department of Accounting
Task Group on Reporting the Effects of Changing Prices and Costs in the Oil and Gas Industry, Financial Accounting Standards Board
Technical Program Committee, American Accounting Association, 1979-1980

SPONSORED RESEARCH PROJECTS: U. S. Department of Interior, "Estimating Rates of Return on Offshore Oil and Gas Leases," 1980-81
U. S. Department of Energy, Advisor to the Office of Leasing Policy Analysis on Net Profit Share Leasing on the Outer Continental Shelves, 1978-81
U. S. Department of Energy, Lawrence Berkeley Laboratories, "Sources of Information Parallel to the Oil and Gas Financial Reporting System," 1979
Arthur Young & Co., on "Issues Before the Securities and Exchange Commission: RE: Oil and Gas Accounting Under FASB Standard 19," 1978
Research Director: American Petroleum Institute Project on "Replacement Cost for Mineral Resources Assets," 1976-1977
Director: Peat, Marwick, Mitchell & Co. Project on Professional Education, The University of Texas, 1975

SPONSORED RESEARCH PROJECTS (cont'd):

Consultant to: American Institute of Certified Public Accountants Project: "A Body of Knowledge for Management Advisory Services," The University of Texas (June-July, 1974)

RESEARCH AND PUBLICATIONS:

a. Articles Published

"Auditor Selection, Organization Control, Adverse Events, and the Selection of Accounting Method for Oil Exploration," Quarterly Review of Economics and Business, Vol. 20, No. 3, Autumn 1980, pp. 77-85

"Reserve Recognition Accounting: How It Came About and Where It Is Headed," Proceedings of the Southwestern Legal Foundation, 1981

"An Analysis of Differences Between Nonmajor Oil Companies Using Successful Efforts and Full Cost Methods," The Accounting Review (October 1979), pp. 722-734

(with C. H. Smith), "The Impact of Earnings Information on Selected Foreign Securities Markets," Journal of International Business Studies (Fall 1978), pp. 43-50

(with Glenn A. Welsch), "Usefulness, Objectivity or Both: The Trade-Off for the Oil and Gas Industry," Oil and Gas Law Journal (December 1977), pp. 203-221

"Accounting Reports, Policy Interventions, and the Behavior of Securities Returns," The Accounting Review (July 1976), pp. 590-603

(with Michael H. Granof), "Regression Analysis as a Means of Determining Audit Sample Size: A Reply," The Accounting Review (April 1976), pp. 402-407

"Directing Audit Effort Using Regression Analysis," The CPA Journal (February 1976), pp. 20-33

"On the Nature of the Distribution of Financial Accounting Ratios: An Empirical Investigation," The Accounting Review (January 1976), pp. 90-96

"Impact of the Retail Land Sales Guide on Reporting Practice," The CPA Journal (August 1975), pp. 43-48

"Finding Optimal Order Quantities when Quantity Discounts are Offered," Cost and Management (May-June 1975), pp. 40-42

RESEARCH AND PUBLICATIONS (cont'd):

(with Edward L. Summers), "A Survey of Curriculum Topics Relevant to the Practice of Management Accounting," The Accounting Review (April 1975), pp. 380-383

(with Michael Granof), "Regression Analysis as a Means for Determining Audit Sample Size," The Accounting Review (October 1974), pp. 764-771

"Teaching Economic Order Quantities under a Price Break System," in James Don Edwards, ed., Accounting Education: Problems and Prospects (The American Accounting Association: October, 1974), pp. 427-430

(with Charles H. Smith), "The Impact of Accounting Information on Tokyo Stock Exchange Volume and Price Activity," International Journal of Accounting Education and Research (Fall 1974), pp. 123-136

(with Barry E. Cushing), "Further Analysis of Firms Making Accounting Changes," The Accounting Review (January 1974), pp. 104-111

"A Class Project for Risk Analysis in Capital Budgeting," The Accounting Review (January 1974), pp. 146-148

(with Michael H. Granof), "Accounting for Retail Land Sales under the New Accounting Guide," The CPA Journal (November 1973), pp. 969-976

(with W. Morley Lemon), "An Operations Research Approach to the Intra-Audit Staff Assignment Problem," Proceedings of the Canadian Association of Administrative Societies (June 1974)

(with Michael H. Granof and Charles H. Smith), "Educational Objectives for an Accounting Program," The Accounting Review (July 1974), pp. 584-589

"Statistical Sampling for the Auditor," The Chartered Accountant in Australia (September 1974)

"A Discriminant Analysis of Predictors of Business Failure," Journal of Accounting Research (Spring 1972), pp. 167-179

b. Invited Presentations

Current Issues in Oil and Gas Accounting, Advanced International Program in Oil and Gas Financial Management, Southwestern Legal Foundation, Dallas, May 1981

RESEARCH AND PUBLICATIONS (cont'd):

Stanford Summer Workshop, July 1978; July 1979

Financial Accounting Standards Board, May 1977 (with
Glenn A. Welsch)

University of Michigan, Accounting Colloquium, February
1977

Salomon Brothers Conference on Financial Institutions,
New York, May 1976

Virginia Polytechnic Institute, Blacksburg, February 1976

c. Presentations

"Direct Testimony of Edward B. Deakin III before the
Securities and Exchange Commission: RE: FASB Standard
No. 19," (File S7-715), March 30, 1978

"Reply to A. D. Little and Co.'s Comments Before the SEC,"
(File S7-715), May 30, 1978

(with Stanley P. Porter), "Accounting Method and the
Structure of Competition in the Oil and Gas Industry,"
(SEC File S7-715), May 31, 1978

"Reporting the Current Cost of Oil and Gas Reserves,"
Southwestern Legal Conference, Dallas, September 1977
(with Glenn A. Welsch)

"Financial Reporting in the Oil and Gas Industry,"
University of New Orleans Oil and Gas Accounting
Conference, April 1977 (with Glenn A. Welsch)

"Financial Accounting and Reporting in the Extractive
Industries," FASB Hearings, March 1977

"Accounting Reports and Policy Interventions," Western
AIDS, San Diego, March 20, 1976

"Using Regression Analysis in Auditing," Western AIDS,
Las Vegas, March 26, 1975

(with Charles H. Smith), "The Absorption of Accounting
Information on International Stock Exchanges," Interna-
tional Conference on Accounting, University of Illinois,
Urbana (May 9-11, 1974)

RESEARCH AND PUBLICATIONS (cont'd)

(with Michael H. Granof), "Regression Analysis in Auditing," Northeast Regional Meeting, American Accounting Association, Philadelphia (April 20, 1974)

(with Charles H. Smith and Michael H. Granof), "Educational Objectives for an Accounting Program" Southwest Regional Meeting, American Accounting Association, Dallas (March 29, 1974)

"Probabilistic Tax Planning," Western Meeting, American Institute of Decision Sciences, San Francisco (March 20, 1974)

"The Audit Staff Assignment Problem: An Operations Research View," Western Meeting, American Institute of Decision Sciences, San Francisco (March 19, 1974)

"Predictions of Corporate Failure," The University of Texas Accounting Department (December 1972)

d. Reprints

"Distributions of Financial Accounting Ratios: Some Empirical Evidence," The C.F.A. Digest (Summer 1976), pp. 24-26

e. Books

(with John J. W. Neuner), Cost Accounting, Principles and Practice, 9th ed. (Irwin, 1977)

(with Glenn A. Welsch), Reporting the "Replacement" Cost of Oil and Gas Reserves (University of Texas Press, 1977)

f. Booklets

Study Guide to accompany Cost Accounting: Principles and Practice, 9th ed., (Irwin, 1977)

Examinations to accompany: Matz, Curry, Usry, Cost Accounting, 6th ed. (South-Western Publishing Co., 1976)

g. Chapters

"Natural Resources," Chapter 39 in J.C. Burton, R. E. Palmer, and R. S. Kay, Handbook of Professional Accounting and Auditing (New York: Warren, Gorham and Lamont, Inc.)

"Budgeting," in H. Black and J.D. Edwards, The Managerial and Cost Accountant's Handbook (Homewood, Illinois: Dow Jones-Irwin, 1979)

RESEARCH AND PUBLICATIONS (cont'd)

"Corporate Bankruptcy Prediction: An Empirical Analysis," in Edward Altman, Financial Crises (Wiley-Interscience, 1977)

h. Monograph

"Accounting for Net Profit Share Leases," Los Alamos Scientific Laboratory, May 1981

i. Book Reviews

Fultz, "Overhead: What It Is and How It Works," in Accounting Review, July 1981, p. 370

j. Publications in Progress

"An Investment Account System for Net Profit Share Leasing," Los Alamos National Laboratories report to the U. S. Department of Energy, in draft (1980)

Cost Accounting: for Resources and Decisions (with M. W. Maher) R. D. Irwin, Inc., forthcoming

TEACHING
EXPERIENCE:

The University of Texas at Austin
Graduate: Accounting 380K.10--Research Methods in Accounting
Accounting 380K.3 --Quantitative Methods in Accounting
Accounting 382 --Studies in Managerial Accounting
Professional Reports--8 chaired, 32 committees
Ph.D. Committees --6 chaired, 17 committees

Undergraduate:
Accounting 329--Managerial Cost Accounting
--Coordinator, 1973 to 1975

University of Illinois
Undergraduate:
Accounting 108--Intermediate Accounting
Accounting 105--Managerial Accounting, Introduction
Accounting 101--Introductory Accounting

PROFESSIONAL
DEVELOPMENT:

Accounting Policy Formulation, U. T. Management Development Programs

"Reserve Recognition Accounting," Executive Enterprises, Inc. (1980: February, May & June)

"Intermediate Accounting," special seminar for Esso Standard Libya, Ltd. (Summer, 1980)

"Current Value Accounting for Oil and Gas," 2nd International Accounting Education Program, Southwestern Legal Foundation (May, 1980)

EXHIBIT II

Theory of Formula Apportionment

Facts:

Two states (A and B)

Net income to be apportioned \$ 50

Location of factor components:

	<u>State A</u>	<u>State B</u>	<u>Total</u>
Property (assets)	\$ 70	\$ 30	\$ 100
Sales	200	65	265
Payrolls	5	2	7

Formula apportionment:

To State B

$$\begin{aligned} & \text{Net income} \quad X \quad \frac{\text{Assets in B}}{\text{Total assets}} + \frac{\text{Sales in B}}{\text{Total sales}} + \frac{\text{Payrolls in B}}{\text{Total payrolls}} \quad \frac{1}{3} \\ \\ = & \quad \$50 \quad X \quad \frac{\$30}{\$100} + \frac{\$65}{\$265} + \frac{\$2}{\$7} \quad X \quad \frac{1}{3} \\ \\ = & \quad \underline{\underline{\$13.85}} \text{ appportioned to B} \end{aligned}$$

EXHIBIT III

Estimated Book Values Of Reserves

Major U. S. Oil Companies

Year: Method:	1980		1979		1978	
	BV	DD&A	BV	DD&A	BV	DD&A
Amerada-Hess	\$1.91	\$1.82	\$1.39	\$1.66	na	\$2.04
Ashland	.97	1.30	1.07	.70	na	na
Atlantic-Richfield	.66a	1.52	.53	1.15	\$.43	1.10
Cities Service	1.71	2.03	1.26	1.54	na	1.47
Continental Oil Co.	1.54a	1.57	1.26	1.16	na	1.34
Exxon	1.22	1.47	.99	1.32	na	.81
Getty	1.59	2.16	1.19	2.00	.92	1.56
Gulf	2.92	2.64	2.40	2.15	1.94	na
Marathon	.90	1.49	.70	1.00	na	.71
Mobil	2.27c	2.38c	1.84	1.59	na	1.34
Phillips	1.03	2.43d	.83	2.18	.67	1.02
Shell	2.42c	2.20c	2.17	1.48	1.12	1.23
Standard-California	1.48	1.64	1.08	1.56	.83	1.30
Standard-Indiana	1.20a	1.84	.99	1.39	na	1.10
Standard-Ohio	.50	1.28	.43	.96	.37	.87
Sun	4.93c	3.07c	1.34	1.75	1.10	1.75
Texaco	1.72	1.75	1.30	1.51	na	1.21
Union-California	.90b	1.72	.69	1.06	na	.81
Weighted Average	<u>\$1.46</u>	<u>\$1.88</u>	<u>\$1.11</u>	<u>\$1.47</u>	<u>\$.78</u>	<u>\$1.14</u>
Average for year	<u>\$1.67</u>		<u>\$1.29</u>		<u>\$.96</u>	

BV Method: Book value of exploration and production property, plant and equipment divided by proved reserves.

DD&A Method: Depreciation, depletion and amortization of exploration and production property divided by production for the year.

U. S. Domestic reserves, production and values only.

Notes:

- a. proved properties only
- b. production properties only
- c. includes significant purchased reserves
- d. includes retirements

EXHIBIT IV

Exploration and Production Income Over
Total Income

	<u>1980</u>	<u>1979</u>	<u>1978</u>
Amerada - Hess *			
Atlantic Richfield	.772	.719	.784
Cities Service	.718	.697	.645
Continental Oil Co.	.700	.556	.540
Exxon	.866	.823	*
Getty	.855	.708	.601
Gulf	.767	.623	.679
Marathon	.762	.828	.834
Mobil	.852	.664	*
Phillips	.943	.637	.546
Shell	.454	.388	.393
Standard - California	.564	.505	.529
Standard - Indiana	.868	.811	*
Standard - Ohio	.928	.915	.888
Sun	.764	.628	.710
Texaco *			
Union - California	.819	.720	.720
	-----	-----	-----
Unweighted average	<u>==.775==</u>	<u>==.681==</u>	<u>==.656==</u>

*Comparable data not available. Ashland Oil Co. has sold most of its producing properties and has announced its intentions to liquidate its remaining producing operations.

Due to noncomparable reporting methods, these data are subject to some estimation error. Certain companies include their foreign operations in the U.S. data when the foreign operations are immaterial. Other companies vary the reporting of transportation activities with some including them in exploration and production. Some companies report segment income before taxes and others after. On balance, these differences should not materially affect the conclusions drawn from the data.

EXHIBIT V

Exploration and Production Assets to Total Assets Major U. S. Oil Companies

	<u>1980</u>	<u>1979</u>	<u>1978</u>
Amerada-Hess *	.	.	.
Ashland **	.	.	.
Atlantic Richfield	.288	.257	.246
Cities Service	.475	.457	.490
Continental Oil Co.	.269	.267	*
Exxon	.394	.381	*
Getty *	.	.	.
Gulf	.520	.513	.517
Marathon	.297	.270	*
Mobil *	.	.	.
Phillips	.196	.190	.209
Shell	.555	.527	.393
Standard - California	.326	.305	.276
Standard - Indiana	.440	.400	*
Standard - Ohio	.510	.653	.754
Sun	.486	.308	.342
Texaco *	.	.	.
Union - California	.394	.339	.308
	-----	-----	-----
Unweighted average	<u>==.396==</u>	<u>==.374==</u>	<u>==.393==</u>

* Data not available

** Ashland has sold most of its producing properaties and has announced its intentions to liquidate its remaining producing operations.

Due to noncomparable reporting methods, these data are subject to some estimation error. Certain companies include their foreign operations in the U.S. data when the foreign operations are immaterial. Other companies vary the reporting of transportation activities with some including them in exploration and production. On balance, these differences should not materially affect the conclusions drawn from the data.

EXHIBIT VI

Exploration and Production Sales to Total Sales Major U. S. Oil Companies

	<u>1980</u>	<u>1979</u>	<u>1978</u>
Amerada-Hess*			
Ashland**			
Atlantic-Richfield	.197	.178	.206
Cities Service	.272	.259	.234
Continental Oil Co.	.119	.111	.118
Exxon	.240	.196	.200
Getty	.288	.351	.350
Gulf	.181	.143	.158
Marathon	.126	.111	*
Mobil*			
Phillips	.123	.119	.131
Shell	.252	.207	.207
Standard - California	.163	.136	.150
Standard - Indiana	.197	.184	*
Standard - Ohio	.408	.308	.189
Sun	.216	.190	.225
Texaco*			
Union - California	<u>.245</u>	<u>.207</u>	<u>.216</u>
Unweighted average	<u><u>.216</u></u>	<u><u>.193</u></u>	<u><u>.199</u></u>

* Comparable data not available.

** Ashland has sold most of its producing properties and has announced its intentions to sell its remaining producing operations.

EXHIBIT VII

Estimated Alaskan Income Using Census Data
(millions of dollars)

<u>Item</u>	<u>1979</u>	<u>1978</u>
<u>Revenues:</u>		
Crude petroleum and condensate	\$ 4,563.4	\$ 2,065.6
Natural gas	109.5	92.5
Royalties and other	9.1	22.0
Total revenues	\$ 4,682.1	\$ 2,180.1
<u>Expenses:</u>		
Direct operating expenses	\$ 294.1	\$ 247.9
Taxes (excluding income taxes)	587.3	239.9
Other indirect expenses	52.3	30.0a
Total reported operating expenses	\$ 933.7	\$ 517.8
Dry hole costs	87.3	166.3
Geological and geophysical	73.5	80.1
Lease rents	10.9	6.7
Total expensed exploratory costs	\$ 171.7	\$ 253.1
Estimated depletion, depreciation and amortization (\$.96/bbl. in 1979 and \$.87/bbl. in 1978 using Sohio's rates)	455.6	363.8
Estimated indirect (overhead) costs:		
Production costs (11.2% in 1979; 12.0% in 1978)	104.6	62.1
Exploration costs (2.7% in 1979; 3.0% in 1978)	4.6	7.6
Total direct costs plus estimated overhead and depletion, depreciation and amortization	\$ 1,670.2	\$ 1,204.4
<u>Estimated Net Income</u>	<u>\$ 3,011.9</u>	<u>\$ 975.7</u>

Source: U. S. Bureau of Census, Survey of Oil and Gas, 1978 & 1979.

a. Data for this specific item for this year were not presented. The estimate is based on the data for the available year adjusted for any change in activity.

Overhead percentages are based on the average of overhead costs to the other costs in each major cost category (Exploration, Production).

Estimated depletion, depreciation and amortization rate is based on Sohio's reported data since over 90% of Sohio's production comes from Alaska.

**INTERIM REPORT OF THE
HOUSE FINANCE SUBCOMMITTEE ON OIL AND GAS**

Prepared by

Louann Cutler, Staff
Representative Al Adams

and

Sharman Piper, Staff
Representative Sam Cotten

at the direction of

Rep. Sam Cotten, Chairman
House Finance Subcommittee on Oil and Gas

January 17, 1986

REPRESENTATIVE
SAM COTTEN
DISTRICT 15



P.O. BOX 296, EAGLE RIVER, AK 99577
POUCH V, JUNEAU, AK 99811

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES

MEMORANDUM

FROM: Representative Sam Cotten *Sam Cotten*
Chairman, House Finance Subcommittee on Oil and Gas

TO: Members of the Alaska State Legislature

RE: Interim Report of the House Finance Subcommittee
on Oil and Gas

DATE: January 17, 1986

One of the most important aspects of Alaska public policy is our treatment of the oil and gas industry. Formulating oil and gas policy is difficult because of the huge amounts of money involved and because the state and the industry have different points of view. The industry is naturally interested in maximizing its profits. State government is concerned with adequately providing for the health, education and welfare of all Alaskans as well as developing its natural resources in a manner consistent with the public interest. Even though the state and the industry are united in our desire to promote oil and gas development, multi-million dollar disputes over fair tax policy and proper valuation of North Slope oil divide us.

Currently facing us is whether to reinstate separate accounting, proposed in House Bill 353, introduced last session by the House Finance Committee. The oil corporations have widely advertised their opposition to the bill throughout the state. Ironically, while they resist the tax changes embodied in HB 353, they have not paid taxes due the state from past tax years, choosing instead to dispute these taxes through established channels. Recent figures from the Department of Revenue (DOR) show the oil companies are hundreds of millions of dollars behind in tax payments to the state, under former and existing tax laws.

During the interim I examined these tax issues and other areas of dispute in order to suggest improvements to state policy, increase our understanding of the issues involved,

and improve our relationship with this vital Alaskan industry.

We depend on an unstable entity -- world oil prices -- for the bulk of our state revenues and this makes it difficult to plan. But even with this uncertainty, Alaska can implement smart business practices. For example, we can't let the oil and gas industry write its own tax laws. On the other hand, we need a policy that encourages exploration and development. We also have to be realistic and realize that state tax incentives alone cannot overcome the current world-wide slump in oil prices.

We need to spend less on government operations and broaden our economic base. Our policies should focus on the decline in Prudhoe production, which will start occurring in the next few years, and the inability of subsequent oil fields to come close to equalling Prudhoe's output. In other words, our present generous level of oil revenues is short-lived. Our goals should be to maximize our benefits now from this non-renewable resource and to encourage additional exploration and production so that we can prepare for a future without as many oil dollars.

It is my hope that this report will help provide a framework for our continuing relationship with the oil industry. Some of the issues discussed here include recommendations for legislation, others are offered as background information.

The topics discussed in the report are as follows: 1) prepayment of disputed taxes; 2) an examination of the issues having to do with separate accounting (HB 353); 3) a discussion of the severance tax and the economic limit factor; 4) an overview of the major oil litigation.

I. Prepayment of Disputed Taxes

One of the most disturbing developments to surface during the interim was the discovery that the oil companies are \$908 million behind in tax payments to the state as of January 6, 1986. Confidentiality statutes prevent disclosing the names of the corporations and exactly how much each owes, but the large sums and statutes involved make it obvious that the major North Slope producers -- Arco, Exxon, Sohio -- are some of the taxpayers whose accounts are at issue. Furthermore, current law offers little incentive for them to pay in a timely manner.

Properly written statutes could have the companies prepay assessed amounts at a set point in the appeals process -- late enough to protect the taxpayers from auditing errors yet early enough to ensure that the taxes are collected in a timely manner.

Additionally, the Legislative Budget and Audit Committee has requested an opinion from the attorney

general's office on the constitutionality of revealing the names of taxpayers whose accounts are past due.

II. The Issues Pertaining to Separate Accounting -- HB 353

HB 353 would reinstate separate accounting as the method used to calculate the oil industry's tax liability. It would also reduce the severance tax from 15% to 12.25%, a substantial incentive to smaller fields. Industry protests about the bill obscure the fact that it is a fairer tax because it lowers the income tax on less profitable ventures, like marginal fields, and puts the tax burden on the most profitable developments, such as Prudhoe Bay and Kuparuk.

HB 353 would ensure that the state receives its fair share of Alaskan oil wealth. On Jan. 13, 1986 the U.S. Supreme Court agreed with the Alaska Supreme Court that separate accounting is constitutional. Furthermore, the state supreme court said that separate accounting is the prevailing method used throughout the United States for reporting income from oil production because it conforms more to an oil company's financial accounting procedures and "more accurately reflects income than formula apportionment".

Under pressure from important US trading partners, President Reagan has asked Congress to force states to abandon worldwide combination formula apportionment.

Whether or not we decide this session to return the former tax law to the books, it's important to understand the basic issues involved and let our decisions on tax policy be guided by facts, not by high-priced media campaigns aimed at our emotions.

III. The Severance Tax and the Economic Limit Factor

This is an issue that needs to be addressed this session because state revenues from severance taxes will be severely reduced beginning in FY 88 if the ELF law isn't changed. The ELF is a statutory reduction to the severance tax, created to extend production on marginal fields, but it is not working as well as it could. Two problems with present law are: 1) it doesn't give marginal fields enough of a tax break; and 2) it will provide Prudhoe with a premature tax reduction decades before it can be considered marginal. A simple change in the ELF law could solve both these problems.

IV. Major Oil Litigation with the Oil and Gas Industry

The amounts at issue in the state's oil and gas litigation are at least \$15 to 20 billion dollars and the state has spent millions of dollars so far to pursue these cases. Major litigation with the oil industry highlights the many points during the production and marketing process that provide profit-making opportunities for the industry and revenue opportunities for the state.

This chapter of the report highlights two major cases that affect the value of the oil and revenues to the state. The cases are the Amerada Hess royalty case and the TAPS tariff case. While the issues involved are in litigation and therefore out of the legislature's immediate realm of influence, I believe knowing more about the nature of the disputes adds to our overall understanding of the subject. Fair prices for the oil and fair charges for transportation costs are the key areas in which the state and oil companies disagree.

The issues summarized above constitute this interim report. It is my hope that the information will be of use to you as we begin the 1986 session. The report does not attempt to address all the facets of the state's complex relationship with the oil and gas industry, but it does touch on some of the important points. I believe staying abreast of the industry and its goals will enhance the quality of state government, because without this knowledge it will be difficult to maintain our positions as the real policymakers of Alaska.

INTERIM REPORT OF THE HOUSE FINANCE SUBCOMMITTEE
ON OIL AND GAS

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I.

PREPAYMENT OF DISPUTED TAXES

I. The Problem

As of January 6, 1986, the oil companies owed the state \$908 million in disputed taxes. Due to the ARCO settlement of \$243 million on January 13, 1986, this total will be adjusted (new figures from DOR are expected next week). Since \$243 million is the amount of the settlement, it may not be the exact amount of taxes previously in dispute between ARCO and the state. The phrase "disputed taxes" refers to audited tax amounts contested by the companies, plus interest and penalties. Unfortunately, existing state law does not encourage speedy resolution of these cases and some of the disputes go back as far as 15 years.

The total reported by DOR to be disputed on Jan. 6, 1986 was \$908,293,008.61. The total amount varies from month to month due to such causes as interest charges and settlement of some of the disputes. For a schedule of all tax accounts receivable, see Attachment A. Here is a breakdown of what is owed:

-- Approximately \$524 million of the total is owed under the former separate accounting oil and gas corporate income tax for the years 1979 to 1981. (AS 43.21)

-- Approximately \$322 million is owed under the severance tax for the years 1976 to 1982. (AS 43.55)

-- The balance of about \$62 million is owed under the income tax statute for all corporate taxpayers.¹ (AS 43.20) While the \$62 million includes contested taxes for all corporate taxpayers, it is estimated that almost all of this amount is owed by the oil and gas corporations.

The main reason the taxes have not been paid is because the oil companies disagree with the state over the amount of their tax liability. They are contesting the tax assessments through established administrative channels in the Department of Revenue. At issue is the methodology for calculating certain revenues and expenses in order to determine the amount of tax owed to the state.

A second reason the taxes have not been paid is that many of the issues involved in the tax disputes are the subjects of major oil and gas litigation between the companies and the state.

A third reason the taxes have not been paid is that the companies appear to have little incentive to do so. Although interest rates on disputed tax liability (12% per AS 43.05.225) may currently be higher than commercial interest rates, it is clearly in the taxpayers' interest to

¹Before 1979 oil and gas companies paid income taxes under AS 43.20, like all other corporate taxpayers. Between 1979 and 1981 they paid income taxes under the separate accounting statute, AS 43.21, and also paid income tax for their non-oil and gas activities under AS 43.20. From 1982 to now, the companies again pay all their income tax under AS 43.20.

prolong the tax disputes and avoid payment for as long as possible. They may also hope for a settlement with the state in which they ultimately pay a smaller amount than originally assessed.

II. The Disputed Issues

The major severance tax issues are similar to those involved in the State v. Amerada Hess, et. al case, though resolution of the tax issues may well be different than the case itself. (The last chapter in this report discusses this case in more detail.) The amount of our royalty share is in question in this lawsuit because of a dispute over the wellhead value of the oil. The wellhead value is determined by the destination price of the oil minus the transportation costs -- primarily pipeline tariffs and tanker charges. The tanker charges and destination price are at issue in the Amerada Hess case and about 95 percent of the total disputed taxes owed under the severance tax law involve these issues.

The remaining severance tax disputes primarily involve:

- 1) what production expenses can be deducted; 2) the computation of pipeline income; 3) what income and expenses are non-oil related and should be taxed under the income tax statutes; and 4) proper pipeline tariffs for non-TAPS pipelines, such as the Kuparuk pipeline and the Panama Canal pipeline.

Roughly half of the separate accounting disputes involve all the issues involved in the severance tax

disputes. The other half of the separate accounting disputes involves these major issues: 1) how to compute production expenses; 2) how to compute pipeline income; 3) income and expenses that should be apportioned to AS 43.20; 4) appropriate pipeline tariff charges; 5) how much should be spent for the eventual closing down of the pipeline; and 6) how much value should be placed on recoverable reserves.

The separate accounting tax disputes are also similar to those in Arco, et. al. v. State, the lawsuit over the state's former separate accounting law (described in the second chapter of this report). Now that separate accounting has been upheld at every level of court review -- most recently by the US Supreme Court this past Monday when it dismissed the oil companies' appeal -- the Department of Revenue expects these tax disputes to progress further.

III. Existing Process for Resolving Tax Disputes

After an oil and gas corporation submits a tax return it is audited by the Department of Revenue. Generally speaking, the audit shows that the taxpayer owes more than the taxpayer's return says. The taxpayer is then assessed the audited amount. Again, generally speaking, the taxpayer contests the audit and the arduous process of resolving the dispute begins.

The first stage of the resolution process is referred to as the informal conference stage and almost 90 percent of currently disputed taxes are in this stage. This is when

DOR and the taxpayer try to resolve factual issues and agree on the amount of tax owed, a process that can take several years. If the dispute is resolved, the taxpayer pays the additional amount and the case is closed. (In some rare instances, the informal conference is skipped and the dispute is taken up immediately at the formal hearing level.)

If it is not resolved, the case moves along to the formal hearing stage. A DOR hearing examiner essentially acts in the capacity of a judge and decides the case. This stage can also take years. The Commissioner can either adopt or reject the decision, although all decisions ever issued have all been adopted.

After adoption of the decision, the taxpayer is required to pay the tax if no appeal is filed in the superior court. If the taxpayer pursues the dispute by appealing to court, then the court will require that a bond be posted in order to continue contesting DOR's decision.

IV. Inadequacy of the current resolution process

Because of our current dispute resolution process, it may take years before the taxpayers will settle or be required to pay the audited tax amounts. Some of the disputes concern taxes that were owed as far back as 1970 although in certain instances, audits may not have been performed until years after a return is filed because the assessment period has been waived.

The taxpayer then has no incentive to resolve the matter since he is not required to pay the audited tax until all the administrative and judicial channels to overturn the audit have been exhausted. By allowing the taxpayer to keep the disputed amounts for so long, current laws appear to encourage the taxpayer to prolong the dispute. Thus the taxpayer will have the disputed funds to invest and earn interest on, or to use for other purposes.

V. A Solution: Prepayment of Assessed Tax Amounts

In order for the state to collect taxes in a more reasonable time frame, the oil companies should be required to prepay the audited amount at some point in the dispute resolution process.

Prepayment could be required after the informal conference stage. At this point the taxpayer and the state have been negotiating and fine-tuning the tax liability for some time. Errors and omissions by the taxpayer and auditor are likely to have been corrected.

Alternatively, prepayment could be required after the formal hearing. The dispute has been reviewed by the entire DOR hierarchy and the Commissioner has adopted a decision. If prepayment is not required until after the formal hearing, specific time frames could be provided in law for each stage of the resolution process. Once the taxpayer has been assessed the audited amount, both the informal conference and formal hearing stages would have to be

completed within a certain number of years established in statute. This would guard against continued prolonging of disputes since prepayment would not be required until the end point of the department's internal review.

It makes fiscal sense to put some or all of the prepayments in escrow until the dispute is finally resolved. The escrow account could be viewed as a form of state savings, since it could still be several years until a particular dispute is finally resolved. In the meantime, the escrowed amounts could ~~earn~~ be invested and earn additional income. This would allow the state to save for the future and also provide protection in the event that the disputed tax liability would be resolved in the taxpayer's favor.

The prepayment requirement should also be applied to amounts owed for prior tax years. Applying the prepayment requirement to past years is essential in order to bring about faster resolution of the current tax disputes, since these disputes involve tax liabilities for earlier years.

Prepayment has precedents at both the state and federal levels. It is currently required by the IRS if the taxpayer decides to appeal to the federal district court or court of claims rather than to tax court. In fact, DOR currently has a prepayment regulation on the books that requires payment of estimated severance taxes but it only applies to the returns for the years after 1984 (14 AAC 55.165). (It also only addresses the issue of oil valuation, not

transportation assessments.) The regulation requires prepayment of an average amount owed by all taxpayers; it does not relate to actual assessed tax liability. This regulation only applies to the severance tax and does not capture back taxes owed under the two corporate income taxes.

A form of prepayment was also a provision of the state's former separate accounting law (in effect for the years 1979-1981). Since the language was vague on whether audited amounts were covered, DOR never enforced the statutory prepayment requirement for the assessed amounts. In enacting this prepayment provision, it is likely that the legislature did not foresee the need for extensive audits and the resultant lengthy dispute resolution process. However, the former prepayment provision can certainly be thought of as a precedent for the kind of prepayment advocated here, especially since the language was never contested by the taxpayers.

The Department of Law has informally advised that there are no legal problems with prepayment. A comprehensive and formal opinion, prepared by both the attorney general's office and the Department of Revenue, is expected early next week.

VI. Conclusion

The legislature should provide by statute for prepayment of audited tax amounts at a set point in the resolution process. This will insure the state receives its

share of oil revenues in a more timely manner and also protect the taxpayers from any initial auditing errors.

Such a prepayment requirement should not be viewed as an additional burden to the oil companies since the revenue that could be raised does not come from implementing new taxes; rather, it is revenue the state should have already received.

ALASKA DEPARTMENT OF REVENUE
APPEALED TAX ASSESSMENTS BY APPEAL LEVEL
 January 6, 1986

TAX TYPE	STATUTE	VALUE OF ACCOUNTS	CONFERENCE	FORMAL	COURT
OIL & GAS CORP INC	AS 43.21	\$524,163,096.65	\$438,358,422.69	\$85,804,673.96	\$.00
OIL & GAS PRODUCTION	AS 43.55	321,697,462.15	300,848,926.97	20,848,535.18	.00
CORPORATE INCOME	AS 43.20	62,432,449.81	47,639,282.76	13,773,985.93	1,019,181.12
INDIVIDUAL INCOME	AS 43.20	2,844,081.31	2,828,965.29	15,116.02	.00
BUSINESS LIC GR RCPT	AS 43.70	2,686,323.31	1,777,731.64	524,380.37	384,211.30
FISHERIES	AS 43.75	1,925,335.87	1,150,173.69	775,162.18	.00
MOTOR FUEL	AS 43.40	1,525,206.60	970,498.59	554,708.01	.00
MINING	AS 43.65	828,697.24	828,697.24	.00	.00
OIL & GAS PROPERTY	AS 43.56	385,779.18	9,321.98	.00	376,457.20
FIDUCIARY INCOME	AS 43.20	183,636.52	183,636.52	.00	.00
SALMON ENHANCEMENT	AS 43.76	42,535.97	29,618.97	12,917.00	.00
ESTATE	AS 43.31	30,840.49	30,840.49	.00	.00
SEAFOOD MARKETING	AS 16.51	8,119.55	8,119.55	.00	.00
INDIVIDUAL WITHHOLD	AS 43.20	7,610.85	7,610.85	.00	.00
TOBACCO (CIGARETTE)	AS 43.50	4,487.22	4,487.22	.00	.00
WMSL CANNED SALMON	AS 43.80	2,250.00	2,250.00	.00	.00
LIQUOR EXCISE	AS 43.60	485.13	485.13	.00	.00
COIN OPERATED DEVICE	AS 43.35	.00	.00	.00	.00
TOTAL TAX ACCOUNTS RECEIVABLE		<u>\$918,768,397.85</u>	<u>\$794,679,069.58</u>	<u>\$122,309,478.65</u>	<u>\$1,779,849.62</u>
PERCENT OF TOTAL VALUE		100.00%	86.49%	13.31%	0.20%

TAX TYPE	STATUTE	NUMBER OF ACCOUNTS	CONFERENCE	FORMAL	COURT
OIL & GAS PRODUCTION	AS 43.55	496	413	83	0
CORPORATE INCOME	AS 43.20	405	314	82	9
INDIVIDUAL INCOME	AS 43.20	253	243	10	0
MOTOR FUEL	AS 43.40	153	92	61	0
FISHERIES	AS 43.75	54	41	13	0
BUSINESS LIC GR RCPT	AS 43.70	42	32	8	2
OIL & GAS CORP INC	AS 43.21	36	21	15	0
SALMON ENHANCEMENT	AS 43.76	20	18	2	0
MINING	AS 43.65	8	8	0	0
SEAFOOD MARKETING	AS 16.51	7	7	0	0
FIDUCIARY INCOME	AS 43.20	7	7	0	0
INDIVIDUAL WITHHOLD	AS 43.20	5	5	0	0
OIL & GAS PROPERTY	AS 43.56	5	4	0	1
WMSL CANNED SALMON	AS 43.80	3	3	0	0
TOBACCO (CIGARETTE)	AS 43.50	2	2	0	0
ESTATE	AS 43.31	2	2	0	0
LIQUOR EXCISE	AS 43.60	1	1	0	0
COIN OPERATED DEVICE	AS 43.35	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
TOTAL TAX ACCOUNTS		<u>1,499</u>	<u>1,213</u>	<u>274</u>	<u>12</u>
PERCENT OF TOTAL ACCOUNTS		100.00%	80.92%	18.28%	0.80%

II.

**OVERVIEW OF ISSUES
PERTAINING TO HB 353**

I. What does HB 353 do?

- A. HB 353 would reinstate separate accounting as the method that the oil industry must use to compute income earned in Alaska to determine its income tax liability to the state.
- B. HB 353 returns the nominal severance tax rate from 15% to its pre-1981 level of 12.25%. The nominal rate was raised in 1981 at the same time that separate accounting was repealed in order to compensate for the loss in tax revenue anticipated at the time due to implementation of modified apportionment.

II. Summary

- A. HB 353 will insure that the state receives its fair share of Alaskan oil wealth. The industry's share has increased since the 1981 tax changes while the state's share has decreased. The changeover has cost the state approximately \$850 million from FY82 through FY86 and an additional \$1.4 billion can be raised from FY87 through FY2005 if the state returns to its pre-1981 tax structure.
- B. The Alaska Supreme Court has found that separate accounting is constitutional in every respect. The court even declared that it is a better measure of oil industry income in Alaska than formula apportionment. The US Supreme Court essentially concurred in this decision on January 13, 1986, when it refused to review the industry's appeal of the state court's ruling.
- C. Separate accounting is a fairer tax because it will lower the income tax on less profitable investments like marginal field exploration and development and raise the income tax on highly profitable fields like Prudhoe Bay (i.e., conventional recovery in the Sadlerochit reservoir). The industry can afford a higher income tax on Prudhoe because it made as much in FY 85 as it made in FY 82 (about \$6 billion in real terms) even with the downward price spiral. Additionally, the income tax increase on Prudhoe would be coupled with a 22% severance tax decrease under HB 353.
- D. Future tax policy should be directed by the overwhelming importance of Prudhoe Bay to our revenue stability. Even with marginal field development, Prudhoe is still expected to provide almost 80% of production through 2010. Almost two thirds of recoverable reserves in Alaska are found in Prudhoe.

III. Background

- A. After four years of comprehensive study, the 1978 legislature changed the method of accounting that oil companies must use to compute their corporate income tax liability from formula apportionment to separate accounting.

It was determined that separate accounting would more accurately reflect how much of an oil company's income is earned in Alaska.

B. The constitutionality of separate accounting was quickly challenged by the major oil companies in Arco v. State. The 1981 legislature was faced with the threat of having to refund about \$9 billion in 1985 when resolution of the litigation was expected. In response to this threat, the legislature repealed separate accounting and enacted modified apportionment in its place. In 1983, an Anchorage superior court judge ruled that separate accounting is constitutional. This decision was unanimously upheld by the Alaska Supreme Court in August, 1985. It was again upheld this past Monday, January 13, 1986, when the US Supreme Court refused to review the industry's appeal of the state supreme court's ruling, thus ending the lawsuit.

C. Definitions:

1. Formula apportionment: If a firm operates in several states and one of the states wishes to tax its income, a method must be chosen to determine how much income was actually earned in the taxing state. The formula apportionment method looks at the firm's worldwide income and, by use of a formula, attributes part of it to the taxing state. The standard formula uses three indicators of business presence in the state: payroll, property and sales.
2. Modified apportionment: This is a modified version of formula apportionment. It is different because of the substitution of the extraction factor for the payroll factor since the former is a better indicator of oil industry presence in Alaska. The extraction factor helps to determine income from oil production by measuring the amount of a company's in-state production activity. Since in Alaska production is far more prevalent than marketing and refining, modified apportionment more accurately determines oil company income and profitability in Alaska than does the standard formula apportionment method.
3. Separate accounting: This method does not use a formula to carve out a portion of worldwide income and attribute it to Alaska. Instead, it takes the wellhead value of oil (gross income) in Alaska and deducts from it all the costs of production to arrive at net income. This amount is then taxed at the same corporate income tax rate that all other non-oil businesses pay. Because it is considered by many to be the most accurate way to measure the value of oil production activity it comes closest to measuring income earned only in Alaska, and therefore, the income of oil companies directly attributable to business activities in Alaska.

IV. What important issues are involved in deciding whether to enact HB 353?

A. Is separate accounting a better, fairer way to tax the oil

industry in Alaska?

- B. Will HB 353 discourage further exploration and development of new oil fields in Alaska?
- C. Will HB 353 destabilize Alaska's business climate?
- D. How will a return to separate accounting affect our tax revenues?
- E. How will a reduction in the severance tax affect our tax revenues?
- F. How will the inevitable decline in Prudhoe Bay production affect Alaska's revenue picture?
- G. Should the legislature consider any other changes to our oil & gas tax structure?
- H. What is the current status of Arco v. State?
- I. Was there a conspiracy in 1981?
- J. How healthy is the oil industry at present?
- K. How does taxation of the oil industry in Alaska compare to taxation of the industry in other states and at the federal level?

These questions are answered in the following sections.

V. Is separate accounting a better and fairer tax accounting method for Alaska?

- A. This issue poses two major questions: (1) Which method -- separate accounting or formula apportionment type of accounting -- best measures the amount of income earned within the taxing state? A fair tax will only apply to income earned in that particular state. (2) What is Alaska's "fair share" of the oil wealth provided by our oil resources?
- B. Question #1 was answered by the legislature in 1978, again by Alaska courts in both 1983 and 1985, and again by the US Supreme Court last Monday. In August, '85, the Alaska Supreme Court stated that separate accounting is the prevailing method throughout the United States for reporting income from oil production because it conforms more to an oil company's financial accounting procedures and "more accurately reflects income than formula apportionment. ...[T]he Alaska legislature turned to separate accounting for oil producing businesses only after it determined that the use of formula apportionment to compute Alaska's share of oil production income would

seriously underestimate the production income that was rightly subject to taxation by this state (emphasis added)." The Court noted further that the case of Sohio is the best illustration of the superiority of separate accounting as a means of allocating income earned in a particular jurisdiction. During the period 1978-80, Sohio maintained that only 10% of its payroll, 12% of its sales and 50% of its property were in Alaska. Yet its 1980 annual report states that over 90% of its total oil production derived from reserves in Alaska. Additionally, documents submitted to the Court (and not disputed by the companies) indicate that Sohio's earnings had elevated it from 17th to 7th industrywide. So, the Court concluded, "... the traditional formula apportionment method would inadequately reflect the phenomenal value of the companies' oil reserves in Alaska."

C. Separate accounting is also superior to modified apportionment because it taxes conventional recovery at Prudhoe Bay more heavily than less profitable ventures, such as new technology applications at Prudhoe, and exploration and development in marginal fields. These less profitable ventures will actually experience an income tax reduction under separate accounting, just as Prudhoe will experience a tax increase. Prudhoe can afford to pay more taxes and still be highly profitable. A 1984 Institute of Social & Economic Research (ISER) study found that Prudhoe had made the companies about \$9 billion in net profits and that its 1982 profit rate hovered around 25%. But some of the riskier investments that industry is making in Alaska that are expected to yield a less-than-average profit could use an additional tax break. This would be a much more equitable approach than modified apportionment which taxes all industry activities at approximately the same rate regardless of risk and expected profit.

D. With regard to question #2, Alaska's fair share should be thought of principally in philosophical terms rather than only in terms of numbers. The following comments were made in a joint statement from the Governor and the legislative leadership in March, 1981: "[A]ny significant decreases in State oil and gas revenues appear both unwarranted and unsupported by the majority of Alaskans. The State's current level of taxation ... provides that both the oil companies and the federal government will receive greater shares of Alaska's wealth than will Alaskans. Accordingly, any greater percentage granted the former at the expense of the latter would be inequitable ... All agree that any changes [to the tax code] that would give large sums of money to the oil industry at the expense of the people of Alaska are unacceptable." These statements express the philosophy behind Alaska's oil and gas tax code and provide a framework for determining if Alaska receives its fair share of the oil wealth. They continue to be relevant in 1986.

E. With this philosophy firmly in mind, consider a "shares" analysis prepared by economist Eban Goodstein in mid 1985. He found that in FY82, shares of oil wealth in Alaska were divided as follows: industry - 41%, federal government - 30%, and state government - 29%. By FY85, the shares had shifted such that industry received 50%, the federal government received 22% and the state received 27%.

F. Alaska is not receiving its fair share as defined by the Governor and the legislature in 1981 because its share has declined while the oil industry's share has increased. Goodstein's analysis further suggests that the change from separate accounting to modified apportionment was one of the reasons why Alaska's share diminished and the industry's share increased. His study concludes that if separate accounting had not been repealed, the FY82 shares would have been 42% industry, 30% federal government and 28% state government while the FY85 shares would have been 47% industry, 21% federal government and 33% state government. A shares analysis prepared by the House Research Agency in December, 1985, compares closely with the Goodstein analysis for the years FY82 through FY85.

VI. Will HB 353 discourage exploration and development?

A. The major determinants of a company's decision to explore and develop a particular oil field are availability of the oil, the price of oil, and the cost of production in that particular field. These factors determine the rate of return which in turn determines whether or not a field will be explored or developed. Since a state's tax rate is only one aspect of the cost of production, and the cost of production is only one factor in the rate of return equation, it follows that the tax rate can only play a small role in the company's final decision to explore or develop. Although taxation may have a psychological affect on a company's decision, it will rarely be the principal factor in the decision making process. The overall rate of return is the ultimate decision maker and the rate of taxation plays only a small part in determining that rate of return. As the ISER report states: "[F]our factors are typically more important than state tax rates in shaping the pattern of resource development." These factors are described as geologic good fortune, ownership of the mineral rights, cost environment and world energy prices.

B. Unlike formula or modified formula apportionment, separate accounting only taxes a company on profits made in Alaska. In fact, a company will only pay a tax on profitable fields in Alaska so that if it has production activity at Prudhoe Bay and exploratory activities elsewhere, it will only pay taxes on the Prudhoe production activity because it does not yet derive any income from its exploratory work. Moreover, separate accounting would allow the company to deduct its

exploratory expenses from its Prudhoe tax liability. Apportionment, on the other hand, taxes a portion of a company's worldwide income so the company will pay taxes in Alaska even if all its profits were made elsewhere and even if its Alaskan activities operate at a loss. Separate accounting, then, is a better incentive for exploration and development since a company will not pay taxes until the field it is exploring or developing starts to produce and generates a profit. In a letter to the House Finance Committee, ISER economics professor Matthew Berman explained this effect as follows: "[S]eparate accounting...has virtually no adverse effect on development of marginal fields. A firm ...will make the investment only if it expects such development to be profitable after subtracting all taxes. Under... separate accounting... the proposed investment...will generate a tax liability...only if the investment is profitable anyway." Berman continues, "Corporate income taxes assessed under the modified apportionment system... may have some adverse effects [because] any investment, profitable or not, will generate an Alaska income tax liability." Berman reaches the same conclusion for exploration of marginal fields. A mid 1985 issue of Pacific OCS News, a trade journal, made a similar observation about Conoco's development of Milne Point: "The start up of this field begins a new era of marginal, N. Slope projects ... If the state returns to the pre-1982 'separate accounting' tax methods, it could offer a significant incentive to this type of small development, because it would be taxed on its own profitability and not on the companies' national profit base."

C. Exploration and development takes place in many jurisdictions that require separate accounting. Foreign nations, the US Government, Oklahoma, Louisiana and Mississippi all utilize separate accounting and all have experienced exploration and development activity.

D. Although the industry indicated to the legislature last session that a return to separate accounting would hamper their exploration and development activities in Alaska, their annual reports appear to lead their shareholders to a much different conclusion. Take, for example, the annual reports of ARCO from 1978 to 1981, the years that separate accounting was on the books. In 1978, ARCO's earnings were up 15%; in 1979, they were up 45%; in 1980, they were up 42%; and in 1981, they were up slightly again. "As it was in 1978", ARCO informed its shareholders, "the North Slope of Alaska was a prime source of the Company's earnings improvement in 1979." Clearly, separate accounting did not interfere with its earnings nor its exploration and development plans. These plans were in fact expanded dramatically during the separate accounting years. The 1979 annual report states: "For its part, Atlantic Richfield has dramatically intensified its search for new domestic reserves of oil and gas." Exploration and development occurred within Alaska during

these years. For example, Kuparuk development was started in 1979 and completed in 1981, "three months ahead of schedule", according to the 1981 ARCO annual report. Surprisingly, the first year that ARCO complains about its tax burden to its shareholders is 1982 -- a full year after Alaska repealed its separate accounting statute.

E. According to economist Goodstein, the oil companies made so much money in Alaska between 1982 and 1985 that \$24 billion in profits went outside. According to ARCO Alaska president Harold Heinze's remarks to the Committee last spring, the industry has invested about \$6 billion in Alaska during this period. Perhaps more of the \$24 billion that went outside would also have been invested in Alaska if separate accounting had been on the books to encourage marginal exploration and development without paying taxes.

F. HB 353 should also encourage exploration and development because it reduces the amount of severance tax that a company would pay. As Vince Wright with the Department of Revenue pointed out to the House Finance Committee in May, 1985, "On the severance tax side ... what you have done is lowered the rate from 15% to 12.25% so in fact ... this might be more of an inducement to expand exploration." For fields that have a 15% rate now, HB 353 would result in a 22.4% reduction in severance taxes.

VII. Will HB 353 create an unstable business climate for the oil industry in Alaska?

A. Since HB 353 will encourage exploration and development, it should make Alaska's business climate even more attractive to the industry.

B. Since 1955, the state's oil tax structure has been through eleven major changes. HB 353 must be viewed in this historical context. A state's tax code should be dynamic and flexible as well as a reflection of a state's changeable economic picture and public policy goals.

C. HB 353 does not create any new taxes. It merely reinstates taxes that were on the books before 1981. Moreover, separate accounting was repealed in 1981 largely because of the threat posed by the lawsuit. The US Supreme Court has laid that issue to rest and HB 353 merely returns our system to its pre-1981 state. The House floor debate on the 1981 amendments indicates that a bill like HB 353 was in fact anticipated. Consider the comments of the majority leader in the House at the time the amendments were enacted: "[B]y that time... we should have an answer to that lawsuit. And with that answer, we should be able to develop possibly a more consistent taxing policy at that time." Apparently it was expected that the legislature would reconsider its oil and gas tax structure

once the constitutional status of separate accounting was determined.

D. It is perhaps more appropriate to view the legislature's 1981 action as the one that created an unstable business climate. This is especially true in light of the fact that the 1981 revisions did create an entirely new method of accounting for income tax liability. Modified apportionment is not used by any other state that relies heavily on oil production activity. And, whereas separate accounting was adopted only after four years of careful, comprehensive study of all tax possibilities, modified apportionment was adopted with little analysis and hardly any debate.

E. Another way to look at stability is from the state's point of view. A stable revenue stream to provide necessary public services is just as important to Alaskans as maintaining a stable business climate. This is especially true in light of the fact that government dollars in large part determine the health of Alaska's economy. The 1981 amendments destabilized our revenue stream because they reduced our share of the oil money. HB 353 returns us to the old system, returns us to our pre-1981 share of the wealth, and, therefore, stabilizes our revenue stream.

VIII. How will a return to separate accounting affect our tax revenues?

A. The Department of Revenue's 10/31/85 fiscal analysis of HB 353 shows that, according to the mean revenue projections, the bill would increase our tax revenues by about \$1.4 billion between FY87 and FY2005. (A new fiscal analysis from DOR is expected in early 1986 that will analyze the impact of the TAPS settlement on the tax structure proposed in HB 353.) Beginning in FY2000, the DOR fiscal note predicts that the state would make less from separate accounting and the lowering of the severance tax than if the higher severance tax and modified apportionment were in effect. This is because of Prudhoe's decline in relation to profits companies will make elsewhere in the world.

B. It is disturbing to note that the Department's analysis shows that the 1981 tax changes have cost the state approximately \$850 million in tax revenues from FY82 through the end of the current fiscal year.

IX. How will the proposed severance tax affect our tax revenues?

A. Because HB 353 lowers the nominal severance tax rate from 15% to 12.25%, severance tax revenues are reduced. However, because of the separate accounting impact, overall tax revenues are increased (see previous section). The DOR fiscal note shows that if the nominal rate was not reduced in HB 353,

the state would gain an additional \$1.5 billion between FY87 and FY2005 or a total additional gain of approximately \$2.9 billion from reimposition of separate accounting and leaving the nominal severance tax rate at 15%.

B. It is important to understand another impact of reducing the nominal severance tax. The actual severance tax paid by the taxpayer depends on the economic limit factor (ELF). When applied to the nominal rate, the ELF reduces the effective rate and therefore the actual amount of severance tax that is paid to the state. Beginning in FY88 when Prudhoe production starts to decline, the ELF will cause our severance tax receipts to decline dramatically because it will lower our severance tax revenues from Prudhoe considerably. According to DOR's June 1985 revenue forecast, FY88 severance tax receipts will be \$230 million less than FY87 receipts. Since HB 353 drops the nominal rate, that change in combination with the ELF will increase the \$230 million drop by another \$143 million, according to calculations made from OMB data.

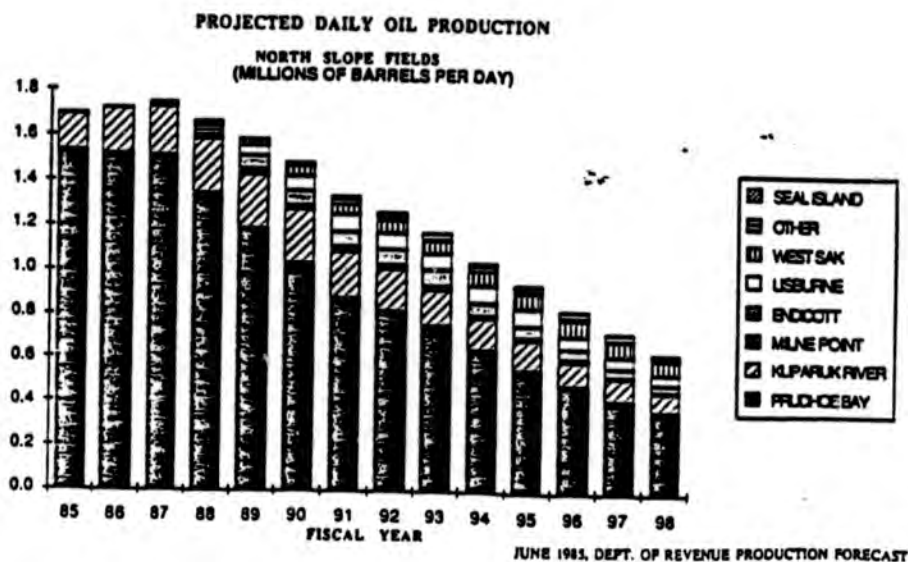
C. An OMB analysis indicates that repeal of the ELF could bring the state an additional \$2.4 billion in revenues from FY87 to FY94.

D. The ELF was developed because it was thought that the burden of the severance tax would tend to close a field down before all the oil was taken out of it. The ELF is designed to prolong the life of a field -- and therefore stretch oil revenues out further over time -- by lowering the tax burden when the field is not producing very much oil. But in its 1984 report, ISER concluded that the ELF does not do a very good job of stretching out our revenues; in fact it only adds an additional year or two to the revenue stream. However, the report does conclude that the ELF is valuable as an incentive to explore and develop marginal fields. This is because marginal fields generally have lower production rates per well, so that the ELF significantly lowers their actual severance tax burden. These conclusions suggest that further consideration of the ELF's impact on revenues and production is warranted and that it should be looked at on an individual field basis since it may encourage production where there otherwise might not be any, such as in a marginal field, but may not have its intended effect on a very profitable field, such as Prudhoe Bay. (Another chapter of this report deals specifically with this problem and proposes one solution to it.)

X. How does the decline of Prudhoe Bay affect our revenues?

A. Prudhoe Bay production to date far outweighs production from any other field in Alaska. The ISER study shows that of the 3.6 billion barrels of oil produced in Alaska from 1959 to 1983, about 3.2 billion of those barrels -- or 90.3% came out of Prudhoe even though the field did not start production

until 1977. ISER also forecast production in the future and found a similar pattern. Using ISER's base case assumptions (real wellhead price of \$17.50 per barrel, declining TAPS tariff, and no change in the federal or state tax structure), of the 8.9 billion barrels likely to be produced between 1983 and 2010, about 6.9 billion -- or 79.4% -- will come from Prudhoe. These figures show that the Prudhoe Bay field is extremely important to Alaska's revenue stability. One draws the same conclusion from the following chart, which depicts production for FY85 through FY98.



B. As Prudhoe declines then, so do our revenues. What is perhaps less apparent is that analysis of future oil production shows that even if all the currently known marginal fields are developed, their combined production cannot make up for the decline of Prudhoe. Lease, tax, and other revenue from development of these fields will not come close to providing Alaska with the wealth it now receives from Prudhoe Bay. As Kay Brown, Director of the Division of Oil & Gas stated to the Permanent Fund trustees, "[B]ased on current knowledge, it is unlikely that new oil and gas discoveries from state lands alone will be sufficient to offset the decline in the main Prudhoe Reservoir. Most of the remaining best prospects appear to be in federal waters and perhaps in the Arctic National Wildlife Refuge." The Division of Oil &

Gas estimates that about 62% of recoverable state reserves in Alaska are in the Sadlerochit (Prudhoe Bay) reservoir.

C. The importance of Prudhoe to our revenue stability should be a driving force in determining the future of Alaska's oil and gas tax structure. It is certainly a valid public policy goal to tax the tremendous profits of Prudhoe Bay. Policy makers should not forget that revenue from production in new fields is not going to make up for the loss of Prudhoe Bay revenues. The \$24 billion in profits that the companies took out of Alaska in the last four years is gone forever; it would be a mistake to continue encouraging them to take their money elsewhere.

D. Although much of Alaska's oil reserves lie off shore, development of these resources will not be a panacea for the decline of Prudhoe, either. These resources are owned by the federal government and therefore, most tax and other revenue benefits will flow back to the feds, not to the state. The only taxes that the state will get are property taxes from onshore facilities. It will not get any lease payments (except from 3-6 miles offshore if President Reagan approves a bill that may be taken up again by Congress in early 1986).

XI. Should any additional changes to the tax code be considered?

A. Ideally, the Alaskan tax code will provide revenue stability to the state even when market forces bring about lower oil prices and even when the quantity of oil in Alaska that can be taxed diminishes. Measuring price and quantity sensitivity is not easy, however.

B. Section VI discusses the fact that separate accounting is a better incentive for exploration and development than modified apportionment because it only requires the payment of taxes when a field is profitable. Many economists believe that a state can facilitate exploration and development of marginal oil fields if it increases the reliance on income taxes and decreases the reliance on severance taxes in the marginal fields. In other words, the state should consider emphasizing taxation of net income instead of gross income in marginal fields. For this reason, Professor Berman concludes that, for marginal fields, net income taxes and net profit shares in leases are superior to excise (such as severance) taxes and royalty shares in leases because a company shares profit with government, not income that just covers expenses. Although 1986 may not be the appropriate time to consider a complete overhaul of our tax and leasing policies, some comprehensive changes may eventually be desirable.

XII. What is the current status of ARCO v. State?

A. The Alaska Supreme Court ruled unanimously in the state's

favor on August 16, 1985. The decision fully supported the state's position that separate accounting is constitutional in every respect.

B. In fact, the Supreme Court went even farther than it had to in upholding the lower court's decision. Instead of stating that separate accounting was an acceptable method of tax accounting, it stated that, for Alaska, separate accounting is preferable to formula apportionment. (See section V for further details.)

C. The oil companies declined to petition the Alaska Supreme Court for a rehearing of the case. In November, 1985 they appealed the decision to the US Supreme Court. The justices declined to take the case on January 13, 1986, thus ending the lawsuit.

D. Though the industry challenged the use of separate accounting in Alaska, it has argued strenuously to be allowed to use it in other states. In at least two states, Wisconsin and South Carolina, the industry took their arguments to the top levels of the court system -- to the state supreme court in South Carolina and to the US Supreme Court in the Wisconsin case. Also, before Prudhoe Bay was in the production stage, the industry tried to file separate accounting returns in Alaska. This demonstrates that the industry is interested in separate accounting when it lowers its tax burden; in other words, when its operations in a state are less profitable than the industry average.

XIII. Was there a conspiracy in 1981?

A. It has been suggested that the oil companies and the Department of Revenue conspired to convince the legislature to enact amendments in 1981 that substantially lowered our fair share of Alaskan oil wealth. Although this point of view is strengthened by the fact that the 1981 amendments now appear to have cost the state about \$850 million, an analysis prepared by OMB suggests that there probably was no conspiracy. The fiscal information provided by the companies to the department, which in turn was used to prepare the legislation's fiscal note, has turned out to be wrong. But it does not appear likely that wrong information was intentionally provided. According to Gregg Erickson, Senior Economist at OMB, "I know of no evidence which would positively rule out the possibility that this discrepancy resulted from an effort to mislead; ... a more plausible explanation is that the oil company experts simply goofed."

B. Although the above information is interesting, what did or did not happen in 1981 should not be the motivation for a

return to our pre-81 tax structure. Rather, the motivating forces should be such aspects of HB 353 as the superiority of separate accounting as evidenced by the recent court ruling, its incentives for exploration and development, and the goal of restoring Alaska's fair share of the wealth created by our abundant oil. In this context it is interesting to note that when the legislature enacted the 1981 changes, it did not repeal the findings section of the original 1978 statute which stated the superiority of separate accounting over an apportionment method.

XIV. Is the oil industry healthy?

- A. It would certainly appear that Exxon is healthy. A recent Business Week article made the following observations: "The only surplus at Exxon Corp. is a surplus of cash. ... The bottom line is that Exxon can make a nice living even if the price of oil falls quite a bit more. ... Salomon Bros. estimates that Exxon will have as much as \$7 billion in spare cash to spend through 1988. ... In fact, Exxon's real limitation is not a lack of money but of enough places in which to invest it profitably." Because prices are down right now, Exxon is frugal with investments and cautious about the future. But it is hardly suffering and couldn't be accurately characterized as anything but very healthy.
- B. The legislature commissioned a report by Tanzer Economic Associates, Inc. in 1977. Among other things, the report examined many historical examples of tax changes throughout the world. It concluded that "there is one effect almost invariably caused by such tax changes. Namely, an almost automatic reaction of the oil companies to claim that such increased taxation will force them to look elsewhere for increased future production. These claims are sometimes backed up by actions, aimed at getting the country to rescind the tax increase, such as temporarily cutting present production or reducing exploration and development efforts. ... Some of the actions and much of the rhetoric ... is 'theater', aimed at improving a bargaining position, and often needs to be taken with a very large grain of salt." One can infer from this observation that the industry will often exaggerate how it will be affected by a tax change in order to keep the change from occurring.
- C. In 1985, the industry uses the current production surplus and price decline pattern as justification for laying off hundreds of Alaskans and cutting daily rates paid to the various oil industry support companies that operate on the Slope. Not surprisingly, it also comes to Juneau and complains bitterly about HB 353, implying that the bill is forcing it to cut back and to consider leaving Alaska. Industry testimony is difficult to accept since we know it is not leaving Alaska, with our Prudhoe bonanza and our

undeveloped reserves, and since we know that HB 353 provides the proper incentives to stay. It becomes even harder to accept when one considers the major factor that explains the majors' current restructuring efforts. Because of falling world oil prices, the fear of takeover is prevalent in industry thinking and the desire to cut costs to a minimum is really motivated by the need to have enough cash around to prohibit an unfriendly takeover (or in the case of some majors, to acquire less healthy companies). Furthermore, declining oil prices is a major factor in the majors' cut backs in exploration activity.

XV. How does taxation of the industry in Alaska compare to taxation in other states and at the federal level?

A. Of the top five oil producing states -- Alaska, California, Texas, Oklahoma and Louisiana, two currently require the use of separate accounting to determine income derived from oil production. These states are Louisiana and Oklahoma. California utilizes formula apportionment and Texas does not have a corporate income tax. (Actually California does require separate accounting in cases where formula apportionment under represents income generation within the state.) In addition, the United States government requires the use of separate accounting in certain instances. Moreover, President Reagan has recently taken an active stance against formula apportionment based on worldwide combination. Since apportionment taxes a portion of a company's worldwide income, some important US trading partners oppose it because they feel that American states take tax dollars away from them. Thus, Reagan has asked Congress to prohibit the use of this kind of formula apportionment at the state level.

B. Another way to compare taxation of the industry in Alaska to industry taxation elsewhere is to compare how much is collected by states from the whole tax code and leasing structure, not just the income tax. The ISER study compared tax and leasing policies in Alaska to such policies in Texas and concluded that "... Alaska and Texas collected approximately the same amount of revenue from oil and gas production." This is interesting because the tax and leasing structure in Texas and Alaska are very different yet, essentially, industry is treated the same. Alaska should not be judged by whether it has a separate accounting or a formula apportionment based income tax but rather by how its policies as a whole impact the oil industry.

XVI. Conclusion

A. HB 353 is well constructed tax reform legislation. It is an attempt to restore Alaska's fair share of the oil wealth to provide Alaskans with desired public services, provide an atmosphere that encourages the oil industry to remain in Alaska, and return Alaska's tax structure to the exhaustively

studied and carefully refined one that existed before it was challenged by the oil companies in the late 1970s.

III.

**THE SEVERANCE TAX AND THE
ECONOMIC LIMIT FACTOR**

I. Introduction

It is generally known that oil producers in Alaska are assessed severance tax rates of 12.25 or 15 percent. However, it may not be so well known that the actual tax rates they pay are much lower than this because of the economic limit factor or ELF. (A severance tax or production tax is a flat tax based solely on the amount produced; in contrast, an income tax is based on profits.)

The ELF is a statutory reduction to the severance tax. It was adopted in 1977¹ to promote production on oil and gas fields with low output and presumably little profit. As the cost of producing the oil gets closer to its value -- the economic limit -- the ELF reduces the tax that is owed. When a field reaches the economic limit the ELF reduces the severance tax to 0. The ELF is applied to both oil and gas, but this discussion deals only with oil.

In practical terms, the ELF dramatically reduces the state's base severance tax rates of 12.25% or 15% on all fields. Prudhoe Bay is a temporary exception to this

¹In anticipation of North Slope production, the Department of Revenue recommended the ELF in its exhaustive 1977 study: "Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement." Previously a "stair-step" approach to severance taxes was used, keyed to Cook Inlet production, with graduated rates to 8 percent. The ELF improved upon the stair steps, retaining the idea that the tax should be reduced as production declined. The ELF also was able to adjust tax rates for both high-volume North Slope fields and the lower-volume Cook Inlet fields.

because of a provision that suspends the ELF for 10 years on high volume fields. However, in FY 88 the 10-year limit expires and Prudhoe will also enjoy tax concessions of the ELF -- and the state will lose \$156 million, according to OMB calculations (see Attachment A). Another example is Kuparuk. In FY 86 the ELF reduced Kuparuk's effective severance tax rate to 6%, and the state lost \$58 million.

An unforeseen consequence of the ELF is that it will greatly reduce the severance tax rates on most of the fields that have yet to begin producing. For example, in FY 90 the effective severance tax rate for Lisburne will be 3% and for Endicott it will be 4%. These cases show that the ELF is actually providing these marginal fields with a substantial incentive -- reducing costs at field start-up.

The ELF's original goal was to extend the life of fields, and thus extend revenues to the state. However, one study shows that the ELF only prolongs a field's life for one or two years, thus its direct benefit to the state is limited. Nonetheless, the ELF does appear to provide an incentive to developers of marginal fields because it reduces the severance tax rate. If the ELF were eliminated, for example, it is likely that some of the marginal fields would not be feasible to develop.²

²In a study entitled "Alaska North Slope Oil Production and Revenue Projections" published Feb. 1985 by the Institute of Social and Economic Research, author and UAA economist Matthew Berman concluded that the Endicott and Milne Point fields might not be feasible to develop without the ELF.

It's also apparent that fields with substantial output and correspondingly high profit rates, such as Prudhoe and Kuparuk, do not require the production incentive that the ELF provides.

II. How the ELF Works

The ELF is a formula that is multiplied by the nominal rate of 12.25% or 15% to obtain the effective rate actually applied to a field. The ELF will never be more than 1. If the ELF is 1, then 100% of the severance tax is owed. An ELF of .8 means 80% of the tax is owed; 80% of 15% equals an effective tax rate of 12%.

Since 1981 the severance tax rate has been 15%, with an exception for new fields; fields that start producing after June 30, 1981 pay a reduced rate of 12.25% for the first five years. The law also requires that the ELF be calculated at 1 during the first 10 years of a field's production any time the ELF goes above .7. (Currently this provision only affects Prudhoe.) For fields with an ELF at or below .7, the actual ELF used. After 10 years the actual ELF is used in all cases.

For example, the ELF for Prudhoe Bay in FY 85 was .864. Since this is more than .7 and within the first 10 years of production, the 1 figure is used. Thus the full 15% severance tax was owed.

In FY 88, however, the 10-year limit will no longer be in effect for Prudhoe (production began in FY 78) and the actual ELF of .82 will be used. This means the amount of severance tax owed will be 82% of 15%, or an effective rate

of 12.5%. The amount to be paid to the state will be \$714 million, \$156 million less than if the full 15% severance tax were paid.

III. Modifying the ELF

It is apparent that the ELF accomplishes its goals but not without some drawbacks. One drawback is providing and unnecessary tax reduction for Prudhoe and Kuparuk. Another issue is whether it goes far enough in reducing the severance tax rate on marginal fields. (A problem with a severance tax as opposed to an income tax is that it is not sensitive to profits or costs, thus a fair tax rate for a large field may be a burden for a small field.)

An additional problem with the current ELF formula is that it is based on daily output per well; total field production is not taken into account. This penalizes a marginal field like Milne Point (30,000 bbls/day) which has high output per well but few wells (about 22). Under the current ELF formula Milne is subject to a severance tax rate almost as high as the tax applied to Kuparuk (240,000 bbls/day), which is clearly not a marginal field. For example, in FY 88, Milne Point will be paying a 7.35% severance tax compared to Kuparuk's rate of 7.6%.

Instead of basing the ELF on individual wells, total field production could be included in the ELF formula to compensate for this inequity, keeping the severance tax low on the smaller fields that would benefit most from a tax break.

The ELF could be modified to accomplish these goals:

-- Dramatically reduce the effective severance tax rates for all marginal fields, including Cook Inlet.

-- Prevent a premature reduction to the severance tax rates for Prudhoe and Kuparuk. These highly profitable fields are years away from being marginal. When they do start approaching the economic limit, the ELF formula will provide them with a tax break.

-- More equitably set the tax rate for each field.

This formula modification would bring Prudhoe's ELF to .99 (now it is at .83); raise Kuparuk's to .8 and drop Milne Point's to .3. These ELF's translate into effective severance tax rates of about 14.85%, 12% and 4.5%.

Here are the current ELF's compared with ELF's under the revised formula.

	Current ELF	Modified ELF	% change
Prudhoe Bay	.80	.99	+23
Kuparuk	.50	.86	+72
Milne Point	.60	.31	-48
Endicott	.31	.0	-100
Lisburne	.11	.05	-54
West Sak	.0	.0	no change
Cook Inlet	.03	.0	-100

The formula change would result in the following positive state severance tax collections*:

FY	millions	
87	\$ 32	* These numbers, based on June 1985 revenue projections, assume the actual ELF is used in all cases and assume a 15% severance tax rate across the board. (If the 12.25% for the first 5 years were retained, there would be little change in these amounts.)
88	179	
89	192	
90	184	
91	175	
92	173	
93	170	
94	158	

IV. What Legislation Would Require

1) Simplify the law so the actual ELF is always applied. Current law requires that an ELF of 1 be used if the actual ELF goes above .7 any time during the first 10 years of a field's production. (AS 43.55.013)

2) Change the ELF formula. (AS 43.55.013) This modification only alters the exponent part of the formula. It uses a different number as a constant and takes into account average daily production from the whole field.

Current ELF formula:

$$ELF = \left(1 - \frac{PEL}{TP}\right) \exp \left(\frac{460 \times WD}{PEL}\right)$$

Revised ELF formula:

$$ELF = \left(1 - \frac{PEL}{TP}\right) \exp \left(\frac{37,000,000 \times WD}{PEL \times TP / \text{Days}}\right)$$

PEL = monthly production rate at the economic limit
(300 barrels x number of well days a month)
TP = total production (number of barrels) during the month
WD = well days in the month
exp = the expression following this is an exponent
Days = The number of days in the month for which the tax is to be paid

The numbers 460 and 37,000,000 are constants or scaling factors.

V. Conclusion

Enacting these changes to the severance tax would not only maintain our current level of severance tax revenue. More importantly, the revised ELF would provide a new

incentive for future oil exploration and production in
Alaska by lowering the severance tax on marginal fields.

ALASKA NORTH SLOPE OIL AND GAS REVENUES

Alaska North Slope Oil Revenue

	Fiscal Years									
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
June 1985 Pet. Rev. Assumptions										
World Oil Price	26.37	24.81	22.41	22.206	22.733	23.464	24.362	25.565	26.934	28.379
Average Rate of Inflation	4.83	3.92	4.81	4.76	4.76	4.76	4.76	4.76	5.184	5.184
ANS/World Qual. & Marketing Adjust	3.253	2.532	2.663	2.639	2.386	2.447	2.475	2.528	2.587	2.612
TransAlaska Pipeline Tariff	6.887	6.887	6.887	6.887	6.887	6.887	6.887	6.887	6.887	6.887
ANS Netback Price 9801 (\$/bbl)	17.11	15.471	13.74	13.56	14.34	15.01	15.88	17.03	18.34	19.76
Prudhoe Bay Prod. (MMbbl/d)	1.528	1.517	1.588	1.34	1.188	1.03	.874	.815	.753	.641
Prudhoe Bay Price (\$/bbl)	17.11	15.471	13.74	13.56	14.34	15.01	15.88	17.03	18.34	19.76
Wells	468.25	589.6	527.1	548.6	524.85	585.15	489.9	466.45	447.65	428.65
ELF	.8648387	.8496946	.8437862	.8285288	.8041141	.7834653	.7548433	.7491265	.7399281	.7145822
Nominal Tax Rate	.15	.15	.15	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	.15	.15	.15	.1238793	.1286171	.1175198	.1131865	.1123698	.1109892	.1071753
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	1252.465	1124.336	992.6137	714.2504	656.2593	588.2696	501.3609	498.1835	489.5263	433.5515
SEVERANCE TAX (NO ELF)	1252.465	1124.336	992.6137	870.4757	816.1278	748.6458	664.8966	664.9124	661.5863	606.7882
CONSERVATION TAX	.6188863	.6856148	.6878219	.5349531	.4742719	.4111953	.3489172	.3253633	.3086117	.2558992
Gathering & Cleaning Charge	.7	.72821	.7567558	.7871817	.8245678	.8638172	.9049349	.9488898	.9931351	1.044619
ROYALTIES	1144.823	1028.395	893.2797	788.9031	732.5782	664.7822	597.1494	597.9988	595.9624	547.3478
TOTAL OIL PROD REVENUES	2396.488	2144.731	1885.893	1495.153	1388.829	1245.052	1090.518	1096.182	1085.489	988.8945
Kuparuk River Prod. (MMbbl/d)	.167	.2	.219	.239	.239	.239	.21	.187	.162	.143
Kuparuk River Price (\$/bbl)	16.29	14.651	12.92	12.74	13.52	14.19	15.86	16.21	17.52	18.94
Wells	154.5	248.5	284	285.25	285.25	285.25	276.5	276.5	254	254
ELF	.69	.4891136	.4697785	.5067934	.5067938	.5067938	.4627634	.4878192	.3773622	.3112742
Nominal Tax Rate	.1275	.1275	.1363	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	.084525	.0599164	.0648297	.0768191	.0768191	.0768191	.0694145	.0618529	.0566843	.0466911
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	73.43848	56.87173	57.86143	73.92498	78.45892	82.33865	78.11249	59.18682	51.38973	48.38798
SEVERANCE TAX (NO ELF)	106.4326	114.6395	123.1696	145.8678	154.7985	162.4697	151.5083	145.2168	135.9694	129.7582
CONSERVATION TAX	.0666695	.0798438	.0874289	.0954133	.0954133	.0954133	.0838359	.0746539	.0646734	.0578883
Gathering & Cleaning Charge	.4	.4885	.4818886	.4815819	.4828838	.4825863	.4838894	.4835132	.4848175	.4845226
ROYALTIES	121.8719	138.8358	125.8883	134.5436	143.8436	158.3448	148.4323	134.8598	126.5885	128.9324
TOTAL OIL PROD REVENUES	194.5183	186.1875	182.9497	204.4685	221.4945	232.6827	218.5448	193.9658	177.8182	161.3283
Milne Point Prod. (MMbbl/d)	8	8	.888	.823	.823	.823	.823	.823	.818	.816
Milne Point Price (\$/bbl)	17.48	15.841	14.11	13.93	14.71	15.38	16.25	17.4	18.71	20.13
Wells	1	1	21.15	21.15	21.15	21.15	21.15	19.6	17.1	15.6
ELF	8	8	.8892881	.6896111	.6896111	.6896111	.6896111	.6159828	.5978649	.5882759
Nominal Tax Rate	.15	.15	.15	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	8	8	.8133928	.8914417	.8914417	.8914417	.8914417	.8951853	.8896797	.8882414
Royalty Percentage	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625
SEVERANCE TAX (ELF)	8	8	.4621848	8.955726	9.457195	9.887944	10.44728	11.46987	9.232479	8.687879
SEVERANCE TAX (NO ELF)	8	8	5.175981	14.69888	15.51349	16.22888	17.13761	18.35842	15.44242	14.76837

SEVERANCE TAX (ELF)	0	0	0	0	0	0	0	0	0	0
SEVERANCE TAX (NO ELF)	0	0	0	0	0	0	0	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	0	0	0	0	0	0	0
TOTAL OIL PROD REVENUES	0	0	0	0	0	0	0	0	0	0

NORTH SLOPE Prod. (MMbbl/d)	1.695	1.717	1.744	1.66	1.504	1.40	1.33	1.257	1.17	1.031
AVG. NORTH SLOPE PRICE (\$/bbl)	17.02921	15.37540	13.63733	13.40789	14.13640	14.74674	15.57237	16.70090	18.00509	19.39853
AVG. NOMINAL TAX RATE	.1472906	.1467967	.1401377	.1460136	.1420015	.1450169	.1469192	.1465652	.1462150	.1475727
AVG. EFFECTIVE TAX RATE	.1435491	.1395069	.1370037	.1115651	.1036090	.0906205	.0934909	.0912105	.0892272	.0830136
AVG. ROYALTY PERCENTAGE	.125	.125	.1251720	.1257340	.1262922	.1264004	.1265956	.1267101	.1267017	.1266031
SEVERANCE TAX	1325.903	1100.400	1050.937	797.1311	746.6525	693.3015	623.0119	617.2010	605.4633	540.1976
CONSERVATION TAX	.6766750	.6054506	.6961006	.6621466	.6314206	.5090927	.5299927	.5000326	.4661775	.4100404
ROYALTIES	1245.093	1150.430	1030.594	960.9079	902.9065	961.0279	916.9057	932.5029	936.9096	890.0760
TOTAL OIL PROD REVENUES	2591.675	2331.524	2082.220	1766.701	1730.190	1655.799	1541.240	1550.366	1542.039	1431.404
	14.35491	13.95069	13.70037	11.15651	10.36090	9.062054	9.349006	9.121049	8.922717	8.301360

FISCAL IMPACT OF ELF REPEAL ON SEVERANCE TAX INCOME
ALL NORTH SLOPE FIELDS

	F185	86	87	88	89	90	91	92	93	94
SEVERANCE TAX (MILLIONS OF \$)										
NO ELF	1350.097	1230.976	1125.702	1039.074	1023.750	1011.050	971.7900	903.0472	903.7061	941.9207
WITH ELF	1325.903	1100.400	1050.937	797.1311	746.6525	693.3015	623.0119	617.2010	605.4633	540.1976
REVENUES RESULTING FROM REPEAL OF ELF	32.99410	50.56776	74.76406	242.7425	277.0974	310.4690	347.9070	365.7653	370.2420	401.7311
CUMULATIVE TOTAL	32.99410	91.56106	166.3267	409.0693	686.1667	1004.636	1352.623	1710.300	2096.631	2490.362

PRUDHOE BAY ONLY

SEVERANCE TAX (MILLIONS OF \$)										
NO ELF	1252.465	1124.336	992.6137	870.4757	816.1270	740.6450	664.0966	664.9124	661.9063	606.7002
WITH ELF	1252.465	1124.336	992.6137	714.2504	656.2593	500.2696	501.3609	490.1035	409.5263	433.5515
REVENUES RESULTING FROM REPEAL OF ELF	0	0	0	156.2253	159.8670	160.3754	163.5357	166.0009	172.0600	173.2367
CUMULATIVE TOTAL	0	0	0	156.2253	316.0931	476.4605	640.0042	806.0131	970.0730	1152.110

Figures calculated
by OMB

IV.

MAJOR LITIGATION

WITH THE OIL AND GAS INDUSTRY

A. Introduction

Alaska is currently involved in one of the largest litigation efforts in U.S. history. The amounts at issue in the state's oil and gas litigation total at least \$15 to \$20 billion. This section of the report focuses on two of the most important disputes with the oil and gas industry, both of which have to do with a single concern: the value of North Slope oil at the point it enters the pipeline. This is referred to as the wellhead value, and the state's tax revenue and royalty value are based on it. The State v. Amerada Hess case is a dispute over the value of the state's royalty oil; the Trans Alaska Pipeline Rate Case addresses proper pipeline tariffs. Both cases involve all the major oil producers and are characterized by their complexity and the enormous effort required to litigate them successfully.

B. The Process of Valuing North Slope Oil

Putting a price on North Slope oil is difficult because unlike oil produced in the Lower 48, most North Slope oil is not sold at the wellhead but rather far from its source, most often on the West Coast or Gulf Coast. Another complication is that much of the oil is refined by the producers themselves, so there are internal transfers within one company rather than third-party sales. In addition, many third-party sales are often done by

exchanges with other considerations rather than a simple price. Thus the value of the oil at those distant markets is not a clearcut issue, and the state contends the producers significantly understate the value of the oil when it reaches its ultimate destinations.

It is important to determine the wellhead value of North Slope oil, however, because it is at this point where the state determines the value of its royalty share and levies the severance tax. The federal government also sets the windfall profits tax at the wellhead.

Thus the value of the oil is determined by the process called netback. To arrive at netback, a destination price is set for the oil (by the oil companies) and then the costs of transportation -- primarily pipeline and tanker -- are subtracted. All three of these values, destination price, tanker costs, and pipeline tariffs, are not easy to determine and thus are the subject of litigation. It is usually to the benefit of the producers to keep transportation costs high in order to keep the wellhead price down and thus reduce the royalties and severance taxes they owe the state.

Compounding the difficulty of valuing North Slope oil is the fact that the producers, notably the three major North Slope producers, Arco, Exxon and Sohio, have different netback methods. They use different methods to set the destination price, different methods to determine tanker transportation costs and different methods of setting the pipeline tariff. Furthermore, a company's

valuation methods may change from month to month. Some months the state may agree with a particular company's figures; another month, it may disapprove of the same company's figures.

The destination price and tanker transportation costs are currently the subject of multi-million dollar litigation over the value of the state's royalty oil. The State v. Amerada Hess case is a dispute over the proper value to be attributed to crude oil when it reaches the Lower 48 and the proper deductions to be made for tanker transportation. (Similar issues are involved in the company's severance tax disputes with the state, but with this case the royalty contracts are at issue.) The TAPS tariff case addresses the third major area of dispute, proper pipeline charges.

C. State v. Amerada Hess

The amounts at issue in this case for both past and future royalties is probably upwards of \$2 billion in present day dollars.

In general, Alaska's position is that the value of the oil should be higher for West Coast destinations than for Gulf or East Coast destinations (because transportation costs to the West Coast are lower). Some companies agree with this premise but disagree with the actual prices, while other companies disagree with this approach altogether.

While it is not easy to get information on the record on the specifics of the valuation disputes, federal hearings¹ in early 1983 over the windfall profits tax reveal how the major producers value their North Slope oil. The hearings focused in particular on the method used by Arco.

Arco sets a single price for North Slope oil regardless of its destination. The price is based on West Texas sour, an oil comparable in quality to ANS crude and actively traded in the Gulf. Transportation costs to the Gulf Coast are then deducted to arrive at a wellhead value for all its North Slope oil. Thus Arco is valuing all of its oil as though it were sent to the Gulf Coast (it costs roughly \$4 more to transport oil to the Gulf). This pricing method has merit in theory, but was severely criticized during the hearings because in fact, Arco sells 70% of its oil on the West Coast. From Alaska's and the federal government's perspective, Arco is artificially setting its West Coast price too low and thus avoiding paying millions of dollars in taxes and royalties.

The oil companies again explained their valuation methods to the Alaska Senate Resources Committee in late

¹The hearings on the windfall profits tax were held in February 1983 before the House of Representatives Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce.

1983.² One of the points made then was that Alaska prefers Sohio's valuation method. Sohio, which doesn't own refineries on the West Coast or in the Gulf, determines value for North Slope crude by finding out how much refiners would pay for comparable foreign crude. Sohio also adjusts its price for destination.

The disparity between the companies' valuation methods results in strikingly different wellhead values. For example, Arco's West Coast price averaged about \$2.50 per barrel less than Sohio's throughout 1984. For 1985, Arco's price averaged about \$1.50 less.

The transportation part of the dispute is complicated by the fact that some producers own their own tankers while others charter tankers. For example, Arco owns about 70 percent of its tankers; Sohio owns none and charters U.S. flagships; Exxon charters about 70 percent of its tankers.

Sohio deducts the actual costs it is charged, while Arco deducts costs based on a national shipping standard called U.S. Freight Rate Averages. Other producers that own their own tankers deduct actual costs of operation and capital investment. Yet another variable for those who charter tankers is whether to use long-term or short-term rates. According to company figures supplied to the federal government, 1982 shipping charges ranged from .78

²The committee held hearings in September 1983 on oil and gas issues.

to 2.35 a barrel for West Coast deliveries, and from 4.29 to 6.63 for Gulf/East Coast deliveries.

In late 1984 the U.S. General Accounting Office³ drew the following profiles of the major North Slope producers based on information obtained from the windfall profits tax hearings. (While the figures are based on 1982 production, the methods and amounts are still fairly representative today.)

SOHIO

Sohio has no refineries on either the West or Gulf coasts. Thus the company either sells or exchanges all of its North Slope oil, about 597,000 barrels daily in 1982. About 40 percent of Sohio's North Slope oil went to the West Coast, about 60 percent went to the Gulf Coast and Caribbean.

For each of these market areas, Sohio negotiates a selling price for North Slope oil based on prices customers would pay for competing imported crude oils, with what the company considers appropriate adjustments for differences in oil quality.

Sohio transports its North Slope oil in chartered US-flag tankers operated by contract with outside parties. From the value received from those arm's-length, third-party transactions in each geographic area, Sohio deducts the pipeline tariff and waterborne and other transportation costs to establish wellhead price in Alaska.

ARCO

Arco uses most of its North Slope crude in its own refineries. In 1982, about 70 percent of Arco's 340,000 barrels per day went to the company's West Coast refinery at Los Angeles. Arco sold an additional 25,000 barrels on the West Coast. The remainder of Arco's North Slope oil, 50,000 to 75,000 barrels, went to the Gulf Coast.

Arco establishes a single wellhead price for its North Slope oil, regardless of its destination. Arco sets its price in the Gulf Coast, based on West Texas sour which is actively traded in the area. From this market price, Arco deducts pipeline tariffs and waterborne costs to the Gulf Coast. The resulting price is the wellhead value for both West Coast and Gulf Coast deliveries.

³The GAO report entitled "Response to Questions About the Windfall Profit Tax on Alaskan North Slope Crude Oil" was published in December 1984.

About 70 percent of Arco's North Slope production is transported in company-owned ships. For these ships Arco deducts U.S. Freight Rate Averages as costs. Actual charges are used for shipments on chartered vessels.

EXXON

In 1982 Exxon produced about 325,000 barrels a day and used about 94 percent of North Slope oil in its own refineries. About one third of its production went to the West Coast, about two-thirds went to its Gulf and East Coast refineries.

Exxon's general approach to pricing recognizes the West and Gulf/East Coasts as separate marketing areas. Exxon's assessment of market value is based on factors such as its own commercial transactions and posted prices of domestic crudes in the area as adjusted for quality. Then Exxon deducts transportation costs to arrive at netback value. These netback values are then averaged by volume shipped to each market area to arrive at wellhead value.

About 70 percent of Exxon's marine transportation is by U.S. chartered tankers.

The Amerada Hess case will require the state to make a detailed factual review of all West Coast and Gulf Coast oil marketing transactions for a seven-year period. The state will have to track the disposition of billions of barrels of North Slope oil. Fiscal years 1986 and 1987 will be peak years of activity for this case, which is currently in the stage of preliminary discovery.

D. The Trans Alaska Pipeline Rate Case

This is the case which has received the most intense litigation effort at this point. The amounts at issue between the best case and worst case outcomes, over the life of the field, are approximately \$7 to \$10 billion.

Ever since start-up of the Trans Alaska Pipeline System (TAPS) in 1977, the state and the pipeline owners have been in litigation over how much the tariff should be. The pipeline tariff -- the per barrel amount TAPS owners

charge for transporting oil through the pipeline -- affects the wellhead value of North Slope oil. The higher the tariff, the lower the wellhead price and the less the state collects in royalties and severance taxes. The state and others say the tariff is too high. (The prevailing tariff charges have ranged from about \$5.60 to \$6.40 per barrel.)

Last summer the state and six of the eight TAPS owners signed a settlement which affects tariffs through 2011; the Federal Energy Regulatory Commission subsequently approved the settlement which is now in effect. The remaining issue is whether to include the other pipeline owners, Sohio and Amerada Hess, in the settlement. After consulting with legislators and state officials in December, the governor decided to give the companies until February 12 to voluntarily join the settlement. If they don't, the state will continue litigation. However, FERC still has the option of imposing the settlement on the companies.

The settlement has had an immediate impact on state revenues, providing a welcome cushion against declining world oil prices. The increase in revenues is due to lower tariffs and therefore higher wellhead values. This TAPS money⁴ has already been incorporated into current revenue forecasts and increased the forecasts by these amounts:

⁴These amounts are what could be termed net gain to the state's unrestricted revenues. The law requires that 25 percent of royalties be put into the Permanent Fund, so the net amount is what is left over after the Permanent Fund contributions.

FY 86	\$ 59.2 million
FY 87	156.9 million
FY 88	136.6 million

The Department of Revenue estimates the settlement will bring from \$120 to \$150 million each year to the state until 1992 and then the amounts will decline. In the late 1990s, the tariffs will start rising and revenues to the state will accordingly decrease.

In addition to the above amounts, the state expects to receive another \$120 million in refunds and legal expense reimbursements. This money has not yet been added to the current revenue projections. If Sohio signs the settlement, the state would receive an additional \$70-\$75 million in refunds. On the other hand, if litigation continues, the state may ultimately receive more money, although litigation always has its risks and resolution could be years away. It's hard to predict at this point if an eight-company settlement will ultimately occur.

FERC's decision approving the six-company settlement has been appealed by the Arctic Slope Regional Corporation and the Alaska Public Interest Research Group (AKPIRG). If an appeal is successful, FERC will hold more hearings.

This is the second attempt in more than eight years of litigation to settle the case. The 1982 effort failed, and the legislature decided to continue litigation to obtain two goals: to establish a rate-making methodology to last through the century, and to establish a methodology that would aid further oil development on the North Slope (meaning lower tariffs in the 1990s). Litigation has been

expensive. The Department of Law has spent over \$36 million on this case alone, not including in-house costs.

The settlement has been highly controversial, drawing fire from several quarters. Last summer the House Majority Leader hired independent economist Jamie Love to analyze the settlement. Love concluded the state gave away too much when it exchanged its litigation position for the settlement. According to Love's calculations, the settlement means the state will lose from \$5.2 to \$6.4 billion through the life of the settlement -- an amount that would be collected if the state's litigation position were to prevail. According to Department of Law figures, however, the settlement means an overall loss of \$2.5 billion (over the life of the settlement) when compared with the state's litigation position. The settlement is also a \$4.5 billion gain when compared with the TAPS owners' litigation position.

Bob Maynard, the assistant attorney general who's handling the TAPS case for the state, says Love made some big errors and used wrong assumptions in his report. Memos from attorneys working on the case to the Department of Law said Love's conclusions shouldn't be the basis of any policy. Maynard also pointed out that the settlement is a compromise which necessarily means the state gets less than if its litigation position were to prevail.

The Alaska Public Utilities Commission also did its own in-house analysis of the settlement late last year and concluded the settlement is not in the public's best

interest and may have an adverse effect on oil exploration and production on the North Slope. APUC thinks the settlement does not adequately balance the competing interests of past, present and future shippers, carriers, producers, royalty owners, the state of Alaska and the federal government. It also shares Arctic Slope Regional Corporation's concern that the rising tariffs at the end of the century will prevent future developers from producing North Slope oil.

There are many aspects of the settlement that contribute to higher tariffs in later years. One of APUC's biggest criticisms of the settlement is that the 35 cent barrel return is not cost-based and may lead to excessive rates of return and tariffs after 1989. APUC also criticized the settlement for eliminating all refund obligations prior to 1982. This means a potential loss of billions of dollars to early year shippers as well as the state of Alaska and the federal government.

A recent decision by FERC on pipeline ratemaking dubbed "Williams II" has been the subject of much speculation. The decision was handed down the same day last June that the state submitted its settlement proposal. The decision appeared to be more favorable to the state's litigation position, though a Department of Revenue analysis of the settlement shows that the settlement may actually be better than a "Williams II" outcome. In any case, it is difficult to say exactly how or if this case would apply to Alaska. In response to a letter written by

some House Majority members opposing the settlement late last year, FERC said the case was not applicable to TAPS.

Settling the dispute relies on how to compute the tariff, which is made up of operating expenses, depreciation, income taxes and after-tax return. Of these four, operating expenses is the least controversial, depreciation and after-tax return the most controversial. The Williams II decision adopted a hybrid ratemaking methodology involving part depreciated original cost and part trended original cost. A depreciated original cost scenario, as set out in the state's litigation position, is much better for the state than the trended for inflation rate base used in the settlement. The inflated base is somewhat of a compromise between the valuation methodology originally sought by TAPS owners and the state's position.

The six TAPS owners who have signed the settlement are: Arco, BP, Exxon, Mobile, Union and Phillips. They collectively own 65% of the pipeline. The other two owners are Amerada Hess and Sohio; Sohio has submitted its own settlement offer to FERC (which Love said would be "disastrous" to the state were it to be approved).

Comments opposing the settlement were filed by Arctic Slope Regional Corporation, Amerada Hess Pipeline Corp., Sohio Pipeline Co. and Sohio Petroleum Co., Tosco Corp., Alaska Oil Co. and AKPIRG.

E. Conclusion

These cases illustrate how various aspects of the

production and marketing process provide profit making opportunities for the industry and revenue opportunities for the state. They show the complexity of valuing our oil and how important that value is to maintaining the financial wellbeing of both parties.

MEMORANDUM

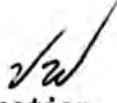
State of Alaska

TO: Mary A. Nordale
Commissioner of Revenue

DATE: October 31, 1985

FILE NO:

TELEPHONE NO:

FROM: Vincent D. Wright 
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.

Mary A. Nordale
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October 31, 1985
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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